THE UNIVERSITY OF ALBERTA

"HIGH VISCOSITY CRUDE OIL DISPLACEMENT IN A LONG UNCONSOLIDATED SAND PACK USING A NATIVE BRINE"

BY

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A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE

STUDIES IN PARTIAL FULFILLMENT OF THE

REQUIREMENTS FOR THE DEGREE OF MASTER OF SCIENCE

IN PETROLEUM ENGINEERING

FACULTY OF ENGINEERING

DEPARTMENT OF CHEMICAL AND PETROLEUM ENGINEERING

EDMONTON, ALBERTA

APRIL, 1964

ACKNOWLEDGMENT

The author wishes to acknowledge with grateful appreciation the generous assistance and cooperation received from the Department of Chemical and Petroleum Engineering of the University of Alberta. He would like to include the shop staff for their help and advice on equipment design and construction. He is particularly indebted to Dr. D.L. Flock, Professor of Petroleum Engineering, for his interest and encouragement to overcome the difficulties encountered. The corrections and helpful suggestions of Mr. P.M. Dranchuk, Associate Professor of Petroleum Engineering are hereby acknowledged.

Acknowledgement is also made to the oil industry for the financial support of the research project in which the author was engaged.

ABSTRACT

A study of the influence of viscosity ratio on recovery efficiency was carried out on an eight feet long unconsolidated sand model employing fluids native to an actual reservoir in the Lloydminster "heavy oil" area.

The average properties of the two packs used were porosity 35.5%, permeability 3.72 darcies. Thirteen tests were run at water saturations varying between 13.0% and 15.4%. The packs were preferentially water wet.

Recovery efficiencies at breakthrough and WOR of 5:1 were obtained at viscosity ratios of 292, 646 and 1430. Viscosity ratio was controlled by temperature variation under a back pressure.

Rate studies were carried out at viscosity ratios of 292 and 646 which revealed a lowering of displacement efficiency at higher rates. This loss in recovery was attributed to viscous fingering. Breakthrough recoveries at low rates were found to be 29.8% and 24.6% of initial oil in place at viscosity ratios of 292 and 646 respectively.

A theoretical recovery versus viscosity ratio was established using Buckley-Leverett theory and experimentally determined relative permeabilities. Actual recoveries were higher than those predicted by theory.

Pressure profiles were used to observe the progress of the front. There was some evidence that higher breakthrough recoveries would be possible with a longer model.

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INTRODUCTION

The purpose of this study was to determine the efficiency of displacement of a high viscosity crude oil from a natural unconsolidated sand using a formation water as the displacing phase. The crude oil, water and sand came from wells in the Lloydminster "heavy crude" area. This is part of a larger research project concerned with the recovery of heavy oils. The impetus for a continuation of this field of research seems to be assured as significant reserves of high viscosity oils are found in southern Alberta and southwestern Saskatchewan in addition to the Lloydminster area. It is also possible that attempts may be made in the future to produce the tar sands in situ. This may be tried in the tar sands proper of the Athabasca area[4] or in other areas of northern Alberta where large "heavy crude" deposits are known to exist[55].

Prior to conducting this study a survey of the water flooding literature revealed that model experiments must be properly scaled in order to make the results more generally applicable. Results of tests involving the immiscible displacement of viscous fluids suggested that particular attention should be paid to rock wettability, rate sensitivity, and effect of viscosity on relative permeabilities.

Fluids actually native to a reservoir were used in this work in order to simulate reservoir sand wettability.

Previous investigations of rock wettability[6, 29, 38, 41] have shown it to be a controlling variable in immiscible displacement. Other work[2, 3, 14] has shown that some reservoir fluids can affect rock wettability.

Scaling experiments[13, 17, 46, 50] have shown that capillary pressure can influence laboratory tests causing recoveries obtained to be rate sensitive. However, by increasing the injection rate a point is reached above which capillary effects are rendered negligible. The same effect has been achieved at lower rates by using longer systems.

Other work[10, 13, 26, 32] has shown that recoveries may be rate sensitive at high rates and high viscosity ratios. This rate influence has been explained as being caused by viscous fingering.

A model, eight feet in length, was designed in order to satisfy the scaling requirements mentioned above. The role of length in scaling considerations is discussed further in a separate section on theory.

In order to establish the original wettability of the sand some tests were run on the long core using articicial liquids at a viscosity ratio of unity. Relative permeability ratios obtained from these tests were used as a basis for determining the wettability. Relative permeability ratios were then obtained from tests using the native fluids and compared.

Variation of viscosity ratio was achieved by temperature control. It was known that temperature affects interfacial tension and possibly wettability[30, 31]. However the effect of changing interfacial tension was considered to be minor[41] and any wettability change would be reflected in the unsteady state relative permeability data[18].

In consideration of the possibility of fingering, properly scaled investigations in this high viscosity range were not available. For this reason rate studies were carried out. Although the exact nature of fingering was not revealed in the tests, its occurrence was verified. Breakthrough recoveries decreased at the higher rates.

Steady state relative permeability curves were obtained at the conclusion of the displacement tests. All the relative permeability data were used to construct a theoretical curve relating displacement efficiency to viscosity ratio. The actual recoveries obtained were higher than those indicated by the theoretical curve. This difference can be explained by the extreme sensitivity of the Buckley Leverett method to small changes in the relative permeability ratios in the particular saturation range of interest.

It is possible the scaling requirements in the model were not completely fulfilled because of the possible effects of the temperature variable. Until further tests are run this might limit the direct application of the results.

REVIEW OF LITERATURE

Although the main object of this work was to determine the influence of high viscosity ratios on recovery, other literature pertaining to water flooding was also reviewed. The work of Uren[54] published in 1928 is of historical interest because it discusses the effect of many of the variables that are still being investigated today. These include capillary forces, rate, presence of gas, oil viscosity, interfacial tension and rock wetting characteristics. The fact that the influence of these parameters is still not fully understood is a testimonial to the complex nature of fluid flow in porous media.

In 1941 Buckley and Leverett[7] developed a theory which attempted to mathematically describe the immiscible displacement process. More recently[8] the theoretical development has been criticized for its lacking rigor. However its usefulness is at present not questioned.

The subject of model scaling received notable contributions from Leverett in 1941[35] and Engleberts and Klinkenberg in 1949[17]. Probably the most influential paper on scaling problems was that of Rapoport and Leas[51] published in 1953. This paper concerned itself mostly with the influence of capillary forces in laboratory models. As will be discussed more fully in the theoretical presentation it was found to be advantageous to minimize capillary effects.

Most of the laboratory displacement tests since the work of Rapoport and Leas have used their scaling criteria. Since short models are most convenient for laboratory use, the necessary scaling condition to attain minimum capillary effects has been achieved by the control of rate.

A non-capillary occurrence of equal importance in model scaling is the phenomenon of viscous fingering. Early reference to this condition was made by Muskat(39) and Engleberts and Klinkenberg(17). A qualitative description of fingering in a model relating it to a non uniform displacement at the inlet end of the core was made by Jones-Parra et al(26). Further work by Kyte and Rapoport(32) tended to confirm that fingering was synonymous with this "inlet end effect". This effect was explained as being localized imbibition of water at the inlet core face. It was suggested that fingering was aggravated by short systems, high water injection rates and high oil to water viscosity ratios.

A quantitative analysis of displacement from a different approach was made by Chuoke et al in 1958(10). Fingering was created at displacement interfaces between parallel plates in a form which could be theoretically predicated. This theory was also applied with reasonable success to oil displacement in a medium of glass beads. Later work by de Haan(13) substantiated the theory and suggested that it applied as well to water wet systems with an initial connate water saturation. Experimental evidence

suggested that fingering would not occur in oil wet systems. Later theoretical developments by Outmans[45] outlined revisions to Chuoke's theory and suggested that viscous fingering in the reservoir would have a negligible effect.

There are a few papers which were concerned with displacement efficiencies at high viscosity ratios i.e. greater than one hundred to one. Of these, the existence of fingering in some form was recognized by Kyte and Rapoport[32], Newcombe et al[41] and Croes and Schwarz[12]. An interesting illustration of the effect of fully developed fingering can be observed by comparing the latter work with that of de Haan. This was not pointed out by de Haan but it seems to be a valid conclusion as the same model was used in both studies. Part of the work of Newcombe et al showed the effects of rate, interfacial tension and contact angle at a high viscosity ratio. They found that high rates caused decreased recovery at breakthrough in a water wet system and that a reduction of interfacial tension gave slightly lower breakthrough recoveries but higher ultimate recoveries.

Two previous works by Felsenthal[19] and Fried[20] were concerned with the influence of viscosity ratio on recovery. Felsenthal did not deal with viscosity ratios above one hundred to one. Fried worked with a short alundum core and did not consider the possible occurrence of fingering.

Moore and Slobod[38] did extensive work on the effect of rate, wettability and core length on recovery.

They concluded that water wet cores did not offer any particular scaling problems. They observed that recovery histories of one inch core plugs were similar to those of long cores when flooded under the same conditions of rate, viscosity level and interfacial tension. It may be significant that though they varied the viscosity of the displaced fluid up to 144 centipoises, the viscosity ratio was kept at approximately one.

It has been a fairly common practice in relative permeability studies to use viscous oils for displacement tests in order to extend unsteady state relative permeability data to a larger saturation range. Referring to this practice, Loomis and Crowell(36) concluded that the displacement method was not entirely trustworthy with water wet cores in the absence of check experiments.

Odeh(42) formulated a theory which suggested that relative permeability was a function of viscosity ratio. Experimental data obtained with fairly high viscosities included non wetting phase relative permeabilities of values much greater than one. Odeh suggested that media of permeability greater than one darcy would not exhibit this phenomenon. Considerable controversy has arisen since this theory was formulated(1).

Much of the previous work on models has involved the use of artificial fluids to avoid the possible influence of impurities(3) and polar compounds(2, 14). There has been a

recent trend toward simulating reservoir conditions as closely as possible[6, 30, 31] in order to reproduce the proper conditions of wettability. It was observed that in many cases cores which exhibited oil wet tendencies at room conditions would become more water wet under the influence of increased temperature and pressure.

THEORY

SCALING OF CAPILLARY FORCES

The fractional flow formula was first developed by Buckley and Leverett[7] for an immiscible displacement. If water is displacing oil in a horizontal system the equation becomes

$$f_w = \frac{1 - \frac{K_o}{\mu_o q_t} \frac{(dP_c)}{dL}}{1 + \frac{k_o}{k_w} \frac{\mu_w}{\mu_o}} \qquad (1)$$

where: f_w - fraction of water flowing at any point

K_o - effective permeability to oil (darcies)

k_o, k_w - relative permeability to oil and water respectively

μ_o, μ_w - viscosity of oil and water respectively (centipoise)

q_t - total flow rate (cc/sec)

P_c - capillary pressure (atm)

L - length (cm)

The influence of capillary forces can be realized by studying the right hand term in the numerator of equation (1). It can be shown that regardless of the wettability of the system the capillary pressure gradient $\frac{dP_c}{dL}$ is always negative. This produces a positive contribution to the numerator indicating a larger fraction of water flowing at

points where there is a capillary pressure gradient. One would expect that an increase in oil viscosity or rate should decrease the capillary effect because they appear in the denominator of equation (1).

These conclusions were confirmed by Rapoport[51] who developed flow equations in dimensionless form to arrive at a "scaling coefficient". It was found that a critical scaling coefficient could be established for a given system above which capillary forces would not decrease the breakthrough recovery efficiency. In a later paper[50] it was verified that increasing the oil viscosity would decrease the value of the critical scaling coefficient other quantities remaining the same.

From the evidence of Kyte and Rapoport[32] the wetting phase saturation build up at the outlet core face (sometimes called outlet end effect) is negligible provided that capillary forces are scaled in the model.

The dimensionless capillary scaling number I as used by de Haan who assumed a zero contact angle is:

$$I = \frac{L v \mu_w}{\sigma \sqrt{K}} \qquad (2)$$

where: L - length (cm)

μ_w - water viscosity (poise)

v - superficial velocity (cm/sec)

σ - interfacial tension (dynes/cm)

K - permeability (cm^2)

The numerator in this expression is Rapoport's scaling coefficient when proper regard is given to the choice of units.

VISCOUS FINGER SCALING

Chuoke's scaling theory is useful to this work despite the theoretical objections of Outmans[45] because it is adaptible to a semi empirical approach.

The following relation was derived by Chuoke et al[10] for the average distance between viscous fingers.

$$\lambda_m = C\sqrt{\frac{\sigma K}{v(\mu_o - \mu_w)}} \qquad (3)$$

where:

	λ_m	average wave length (cm)
	σ	interfacial tension (dynes/cm)
	K	permeability (cm^2)
	v	superficial velocity (cm/sec)
	μ_o and μ_w	oil and water viscosity (poise)
	C	constant (varies with system)

The smallest wave length possible at the onset of fingering is called the critical wave length λ_{cr} which is related to the average distance between fingers by

$$\lambda_{cr} = \lambda_m/\sqrt{3} \qquad (4)$$

No fingering will exist when λ_{cr} is greater than the largest lateral dimension of the system. In applying this criterion to a reservoir, de Haan used the thickness

of the reservoir as the reference dimension of the system. This seems to be a point of possible controversy but has been accepted for this development. The displacement efficiency at breakthrough is a function of the number of fingers which is in turn a function of the rate of displacement. When about five or more fingers have formed the system is no longer rate sensitive, and recovery efficiency at breakthrough stabilizes at some lower level. Fingering does not appear to occur in oil wet systems.

The constant C takes into account the fact that the interfacial tension at the interface in a porous medium containing a connate water will be something greater than that measured at a planar interface. de Haan suggests a C value of about 300 when connate water is present.

If the onset of fingering is observed in a given system, C can be evaluated because at this point λ_{cr} must be equal to h so that

$$C = \sqrt{\frac{3v(\mu_o - \mu_w)h^2}{\sigma K}} \tag{5}$$

where in the case of a core, h is the diameter in cms.

COMPATIBILITY OF CAPILLARY NUMBER AND FINGER SCALING

The application of the capillary number and finger scaling to a model might appear straight forward. It is required to make these quantities the same in the model as in the reservoir without violating other scaling groups.

The most convenient parameter to adjust in the model is rate and this can be best illustrated with the use of examples.

Case I: Reservoir conditions: Fingering absent
Stabilized zone negligible.

It is necessary to find a rate for the model which would result in a capillary number greater than some minimum value. de Haan suggests $I > 0.1$. If this rate causes fingering it would be impossible to properly scale the test without re-designing the system.

The point to be made here, which is applicable to this work, is the desirability of having a long core when finger scaling is an unknown factor; i.e. C is unknown. The model length does not enter finger scaling directly but a long core permits capillary scaling criteria to be fulfilled at lower rates.

Case II: Reservoir conditions: Fingering present
Stabilized zone negligible.

This does not involve a scaling problem because a rate can likely be set to scale the fingers and it is reasonable to assume that at this rate capillary effects will be absent.

However in order to hypothesize the existence of fingering in the reservoir a C value must be available from some other experimental data. Therefore it might be advisable to carry out a rate study to verify this value.

EXPERIMENTAL EQUIPMENT

The core holder was an 8-foot section of schedule 80 steel pipe of 1-1/2 inches inside diameter. A 1-1/2 inch series 900 flange was welded to each end. The flanges were made up using a brass gasket dressed with Garlok Sealing Compound No. 101.

The sand was held in place by sintered bronze discs which were tapped snugly into place, flush with the end of the core. The presence of the flange gasket insured a void space sufficient for good communication across the core face.

Pressure points were located every foot along one side of the pipe. Small sintered bronze discs located above the 1/8 inch ports prevented loss of sand from the pipe.

Two different views of the entire apparatus can be seen in Figure 1.

The entire core assembly was set inside a rectangular metal box long enough to accomodate inlet and outlet connections and deep enough to completely submerge the flanges in a bath oil. The oil was circulated continuously and the temperature was controlled to within $\pm 1.0^{\circ}F$. The primary heat source was an electrical element. Additional piping within the bath was used to circulate water as necessary to expedite heating or cooling.

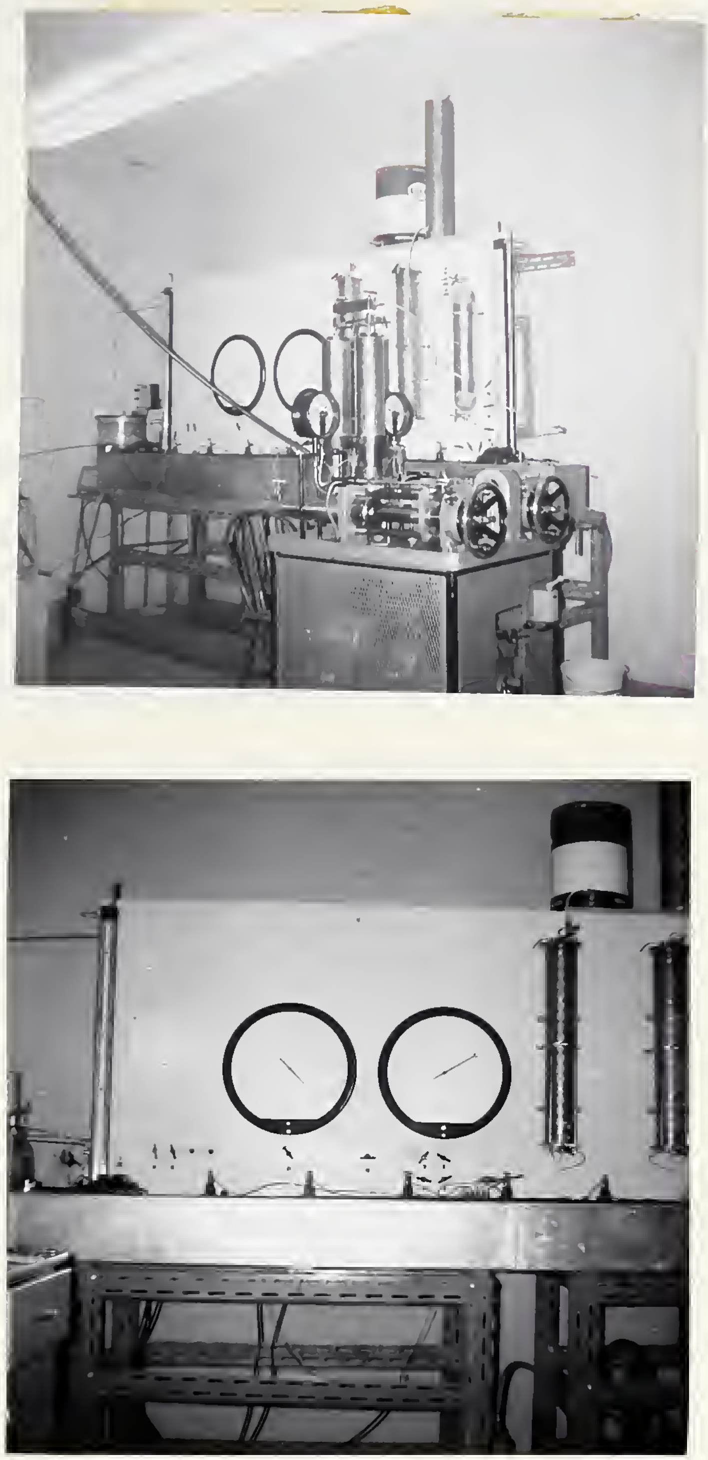
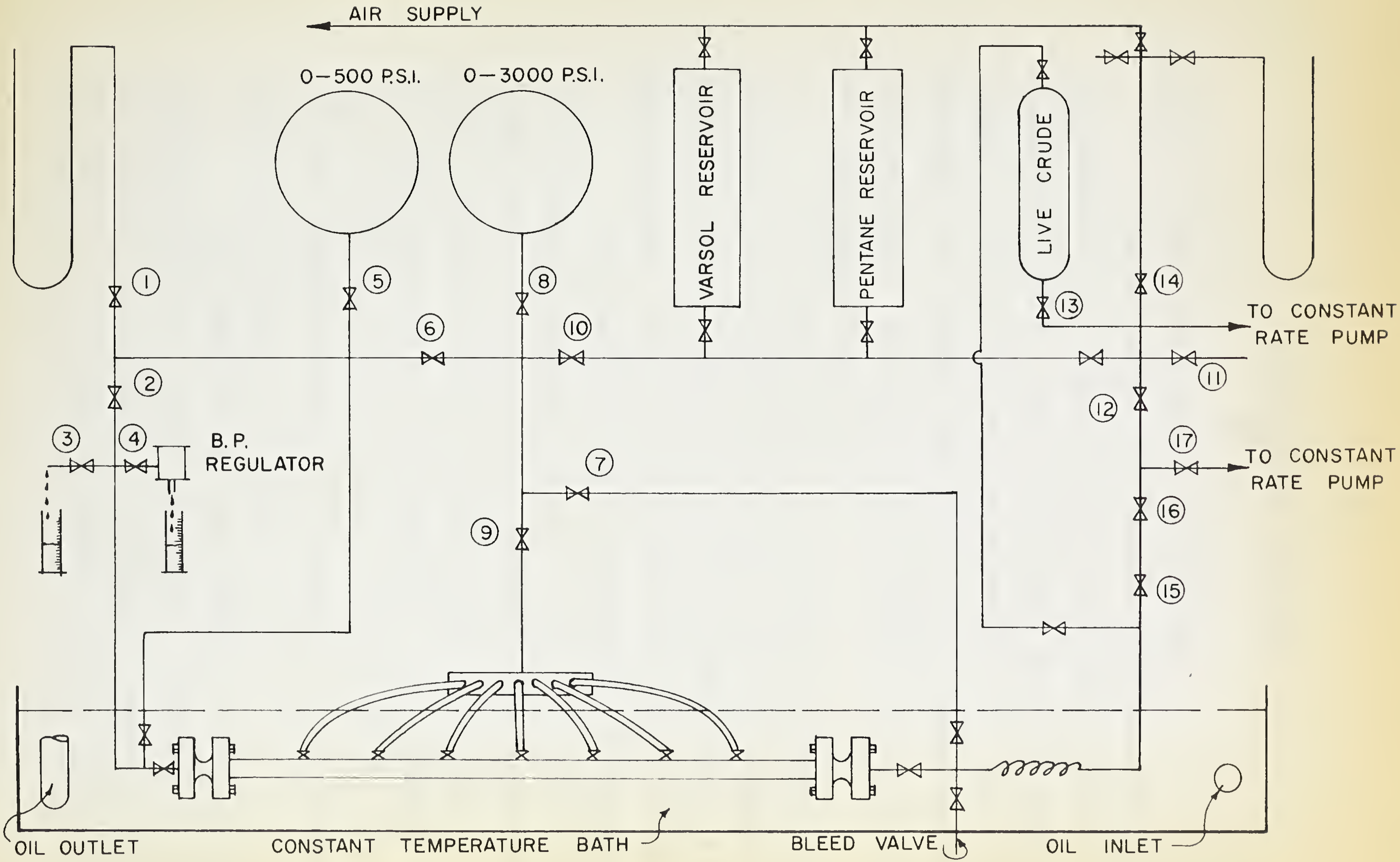


Figure 1: Experimental Equipment

A model 2249 W II double barrelled constant rate Ruska pump was used for all tests. Shown in the top photo of Figure 1, are the stainless steel reservoirs which were used to hold the brine and dead crude.

The collecting graduates were kept in a settling bath controlled at the same temperature as that of the core.

A schematic diagram of the equipment is shown in Figure 2. Provision for the use of live crude was made although this was not used for the tests. Varsol was used in the lines to transmit pressure to the Heise gauges.



SCHEMATIC DIAGRAM OF DISPLACEMENT TEST APPARATUS FOR EIGHT FOOT LONG PACK

FIG. 2

EXPERIMENTAL PROCEDURE

SOURCE, STORAGE AND HANDLING OF MATERIALS

Natural sand from a lease storage tank was used. The sand was first washed with hot tap water and then flushed with Varsol. The sand was then given alternate washes of benzene and distilled water until all traces of staining were removed. Some fines may have been lost during these washings. The sand was then placed in a drying oven for a few hours at about 250°F.

The crude oil used in all tests was obtained after treatment for removal of water only. Crude oil viscosity was measured at room conditions with a Brookfield rotating bob type viscometer using as calibrating oils SAE 20, 30 and 50.

Viscosities at higher temperatures and pressures were obtained from tests on a 14 foot piece of 1/16 inch inside diameter copper tubing immersed in the temperature bath. A constant for this system was obtained based on the crude viscosity at room conditions. This constant was used to convert pressure drops at other conditions into viscosities. Welker and Dunlop[57] describe a more elaborate set up for this type of equipment.

The formation water was filtered through filter paper and stored in a glass container. Considerable rust was removed. It was usually necessary to filter the brine again when it was transferred to the lucite storage reservoir.

The brine was de-aerated before using.

Surface and interfacial tension measurements were made with a Du Nouy ring tensiometer. As the constant temperature bath was separate from the instrument the container was brought to bath temperature and quickly moved to the instrument platform. The temperature of measurement was taken as an average of the bath temperature and the temperature obtained immediately after the ring pulled free.

The measured fluid properties are shown in Figures I-1 to I-5 and table I-1 of Appendix I. Attention is drawn to the fact that the injected and effluent fluids had different interfacial tensions presumably due to the filtering action of the sand pack.

PACKING THE CORE

One end of the core holder was completely flanged up with the bronze screen in place and a bull plug inserted in the port. The core holder was placed in a vertical position and half filled with distilled water. While dry sand was poured into the top using a funnel, the base of the pipe was vibrated using a 1/2 H.P. electric hammer. Within an hour the water level rose to the level of the upper flange. At this point a piece of 1-1/2 inch outside diameter lucite about 1-1/2 feet long was inserted inside the top of the core holder. The sand was then poured through the lucite and when the sand level did not change with continued vibration throughout

the entire length of the core holder the packing was terminated.

DETERMINATION OF FUNDAMENTAL CORE PROPERTIES

To obtain the porosity the core was dried for one day at a temperature of 130°F. Operating the Ruska pump by hand, de-aerated brine was injected into the evacuated core until fully saturated. The pore volume was then calculated from the pump readings.

Prior to brine saturation of the core an air permeability was run at room temperature. The upstream and downstream pressure taps were not located at the end faces as recommended by Hamilton[21]. The effect of this on the obtained pressure profile could not be ascertained because of the variation in permeability inherent in the packing procedure. Following saturation of the core with brine, permeability profiles at 100% liquid saturation were recorded. In the case of pack number 5 many of these profiles were run at various times using Varsol as well as brine as the saturating liquid. The sand and test model properties are shown in Figure 3.

Initial imbibition tests were run on small sand cells, saturated with Varsol and immersed in distilled water. The results indicated the sand was water wet. When Lloydminster crude was used as the saturating oil no imbibition was observed. This was attributed to the effect of viscosity on imbibition rate.

Five displacement tests were run on core pack number 5 using Varsol and distilled water. The objectives sought were to study the relative displacement efficiencies of oil and water as the displacing phase, and to obtain an unsteady state relative permeability curve which could be used as a reference for similar curves obtained from later displacement data. In two of the five tests the water was treated with sodium carbonate to promote a water wet condition[25].

Steady state relative permeability tests were run at the conclusion of the displacement tests. The range of water oil ratios selected varied from 1:3 to 15:1. The total flow rate was always close to 30 cc's per hour. At the conclusion of the last ratio the rate was dropped to 10 cc's per hour to check for possible rate sensitivity. No provision was made for differentiating between the pressure drop in the water and crude phases. Saturation equilibrium within the core was considered attained when injected and effluent water oil ratios were identical and the pressure profile was reasonably constant. The steady state relative permeability data are shown in Tables II-1 to II-4 of Appendix II along with a sample calculation.

DISPLACEMENT TESTS

Sixteen displacement tests were carried out with the core saturated at some initial brine saturation. These

tests are numbered 6 to 21. Tests 6 to 8 involving an 11% water emulsified crude do not form a part of this thesis. Tests 9 to 13 inclusive were run to study the effect of rate at the viscosity ratio obtained at 100°F. Conditions between tests 9 and 10 were not changed. The core was repacked after Test 13. Tests 14 to 16 were carried out on pack number 6 at a constant rate of 30 cc's per hour and the viscosity ratios obtained at temperatures of 77°F, 100°F and 130°F. Test 17 to 21 comprised a rate study at 130°F. The direction of flow was reversed for Test 21.

When saturating the core with crude it was found that very little water was displaced after breakthrough of the crude at the outlet end and an irreducible water saturation no greater than 13% was indicated for the sand. During a displacement the average water saturation of the core would rise to about 40% or greater depending on the cumulative brine injected. This value could be restored to its initial value by the injection of about one pore volume of crude at the conclusion of a displacement. This procedure for resaturation has been recommended by Maguss(37).

While reinjecting crude after Test number 15 the bath temperature was increased from 77°F to 130°F. The volume of effluent fluid exceeded the injected volume by 25 cc. This amount was in line with that expected from thermal expansion.

A pressure profile was recorded prior to each test to confirm re-establishment of saturation equilibrium within

the core. While obtaining a profile during the displacement the front would move a significant distance depending on the rate. Therefore a time interval was recorded for each profile and, in addition, the exact time the pressure was recorded at the tap most recently passed by the front. Profiles obtained at high rates had fewer anomalous points than those at low rates. At the lowest rate of 2.5 cc's per hour the front was difficult to discern from the pressure profile. This was attributed to the fact that the capillary pressure was of the order of the applied pressure gradient. Pressure data are shown in Tables III-1 to III-13 of Appendix III.

Breakthrough was anticipated fairly well by observing the pressure profiles. Just prior to the appearance of large discrete water drops in the effluent, the downstream pressure would fall slightly due to an effect at the back pressure regulator. The most diagnostic evidence was obtained using a sonic viscometer with a vibrating probe. For some reason, possibly emulsification brought about by the high shear rate, the first appearance of water was signalled by a sharp increase in the viscosity reading. This instrument was used for Tests 9 to 13. The use of this instrument entailed the introduction of a cell of 7 cc volume at the end of the core. Because of the channeling action of the water past the crude in the cell, corrections to the recoveries were difficult to administer for which no

satisfactory solution was found. For this reason this instrument was not used for Tests 14 to 21.

The water in the effluent was separated from the oil in a settling bath. Recoveries with small water cuts were centrifuged to make sure that volumes measured after settling alone were not in error due to emulsification. There was a tendency for droplets of crude to cling to the sides of the graduates if they were not thoroughly cleaned. Therefore glassware was rinsed with concentrated hydrochloric acid when cleaning. Recoveries for the tests are shown in Tables III-14 to III-26 of Appendix III.

To clean the core the temperature was raised to 130°F to reduce the crude viscosity. Using air pressure, Varsol was first injected through the pressure taps until free flow was obtained. Varsol then was injected at the upstream end until the effluent was clear. This required about 5 gallons of Varsol. This was followed by about a gallon of pentane, which was then blown out with dry air.

INTERNAL CORROSION

When repacking the core the bronze end screens as well as the inside of the core holder were observed to be covered by a black deposit. This appeared to be a corrosion product.

DISCUSSION OF RESULTS

MODEL PROPERTIES

Referring to Figure 3 it will be noticed that although pack number 6 had a slightly coarser grain size distribution than pack number 5 the latter had a slightly higher porosity and permeability. This may be explained by a difference in the packing technique employed in each case. Pack number 6 was packed in a period of about 3 hours. The packing of sample number 5 was interrupted for a period of days and a smaller electric hammer was used. This also may explain why pack number 5 had a minimum permeability near the middle instead of at the top as was the case of pack number 6.

PRELIMINARY TESTS

The recovery histories for the five displacements at unity viscosity ratio are shown in Figure 4. Higher breakthrough recoveries were obtained when displacing Varsol with water. The recovery histories of the treated and untreated water displacements were reasonably similar. The sodium carbonate treatment was intended to insure a water wet sand[23].

Relative permeability ratios obtained from these tests are shown in Figure 5. These were calculated using the Welge modification to the Buckley-Leverett theory. Some

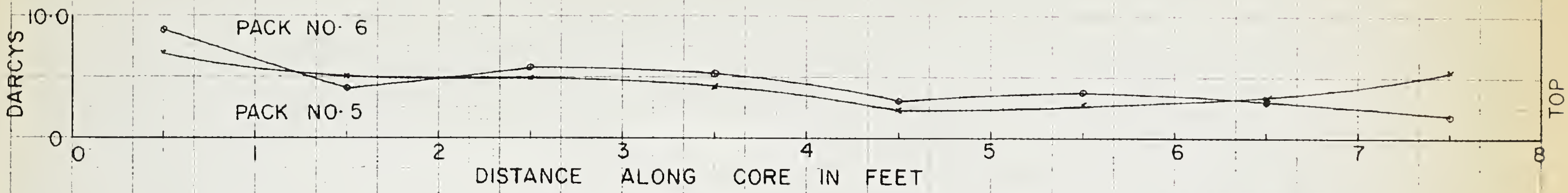
points obtained subsequently from tests using crude and native brine are shown as well. It was possible to establish a representative line through these data points. Also shown on this figure is an area covering the wettability spectrum as established by Fatt and Klikoff[18] for a pack of reasonably similar grain size distribution. A comparison of the curves would suggest that pack numbers 5 and 6 were water wet. The data points of the preliminary tests were obtained from a drainage direction saturation change. It was necessary to use these points to establish a curve in the saturation range of interest.

The recovery and pressure histories for two of the preliminary tests are compared with recovery and pressure histories for two different wetting conditions as obtained from the work of de Haan[13] in Figure 6. The "water displacing Varsol" curve of this work resembled the intermediate wettability case in de Haan's work. Intermediate wettability was defined by de Haan as being weakly preferentially water wet.

DISPLACEMENT TESTS

The discussion of the tests involving the crude oil of high viscosity will be concerned with uniformity of initial conditions, actual recoveries obtained, evidence of fingering, ideas on the subordinate production mechanism, theoretical recovery and comparison of the theoretical recoveries with those obtained from the literature.

BRINE PERMEABILITY PROFILES



	ϕ	K_{liquid}	K_{air}
+ NO·5	36·4	3·82	5·01
⊙ NO 6	34·5	3·62	3·79

MODEL DIMENSIONS

LENGTH 244·0 CM

DIAM. 3·81 CM.

SIEVE ANALYSES

U.S. MESH NO.	WGT. % RETAINED PACK NO. 5	PACK NO. 6
60	5·5	8·9
80	26·8	37·0
100	32·8	32·8
120	15·2	8·7
140	8·5	4·5
200	6·6	5·6
200−	4·6	2·4

FIG· 3 PROPERTIES OF SAND AND TEST MODEL

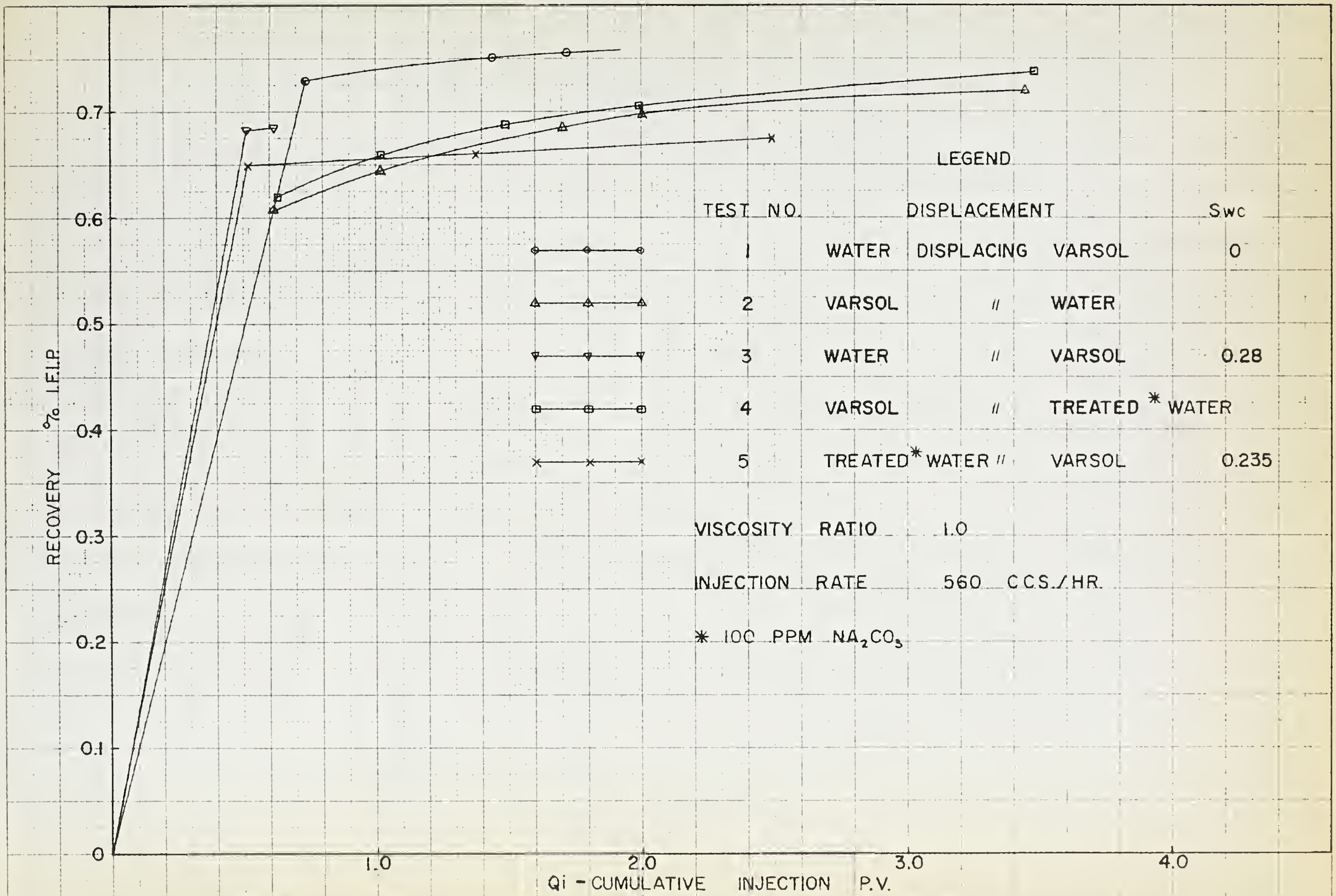
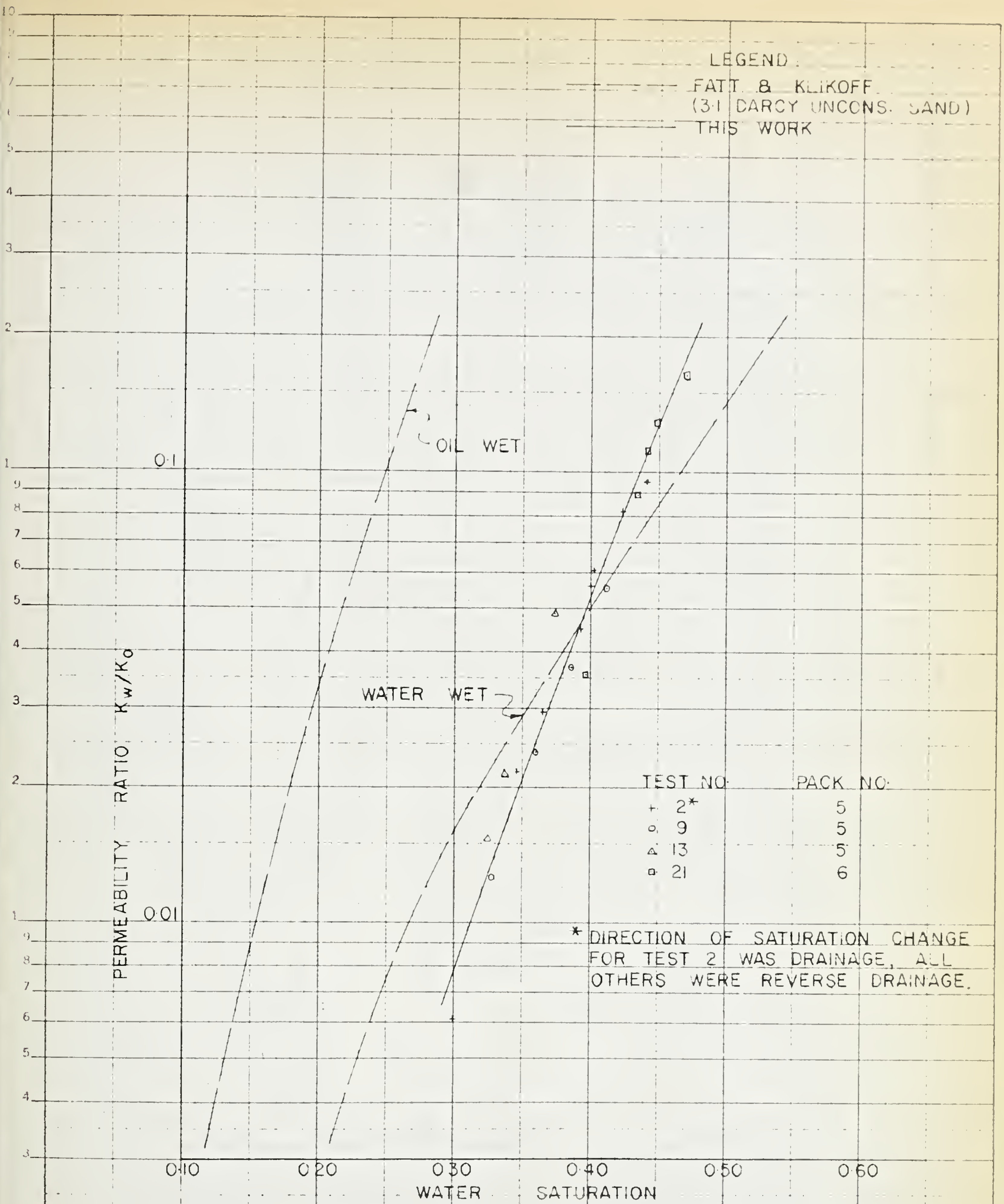


FIG. 4 PRELIMINARY DISPLACEMENT TESTS USING TEST OIL AND DISTILLED WATER



FIG· 5 PERMEABILITY RATIOS OF MODEL COMPARED TO CURVES OF FATT & KLIKOFF (18)

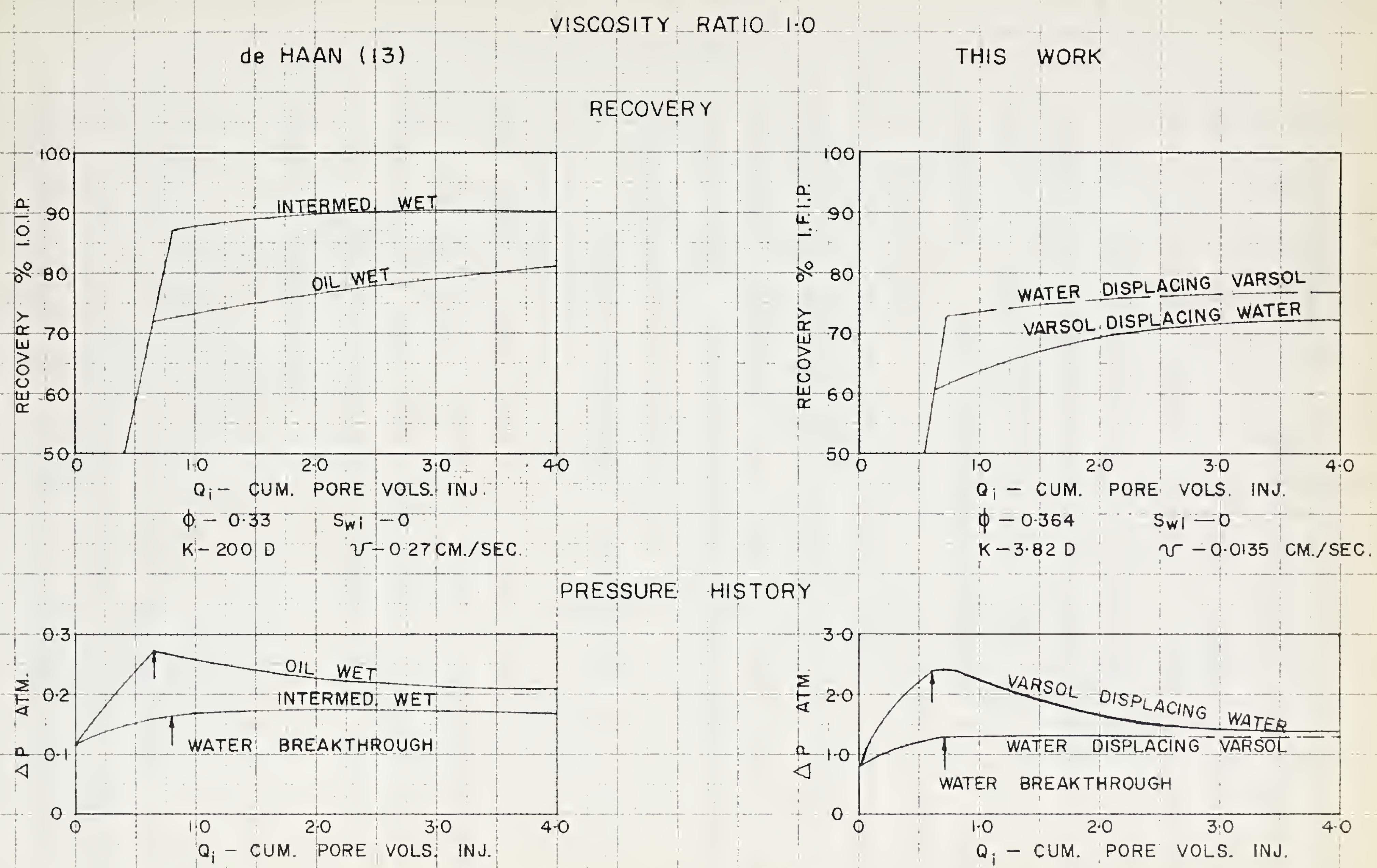


FIG. 6 COMPARISON OF RECOVERY AND PRESSURE HISTORY OF PRELIMINARY TESTS TO TESTS BY de HAAN

Initial Conditions. A summary of the initial test conditions is given in Table I. It will be noted that initial water saturation was controlled within reasonable limits and the small variations did not appear to correlate with any other factor. This was not true of the values for the relative permeability to oil at connate water saturation however. There are three fairly obvious trends perceivable. Firstly pack number 5 exhibited higher effective oil permeabilities than pack number 6. Secondly the effective permeability decreased as the temperature increased. Since most of the runs at low temperature were made on pack number 5 the differences might have been due to either packing, or temperature or both. Thirdly, the effective permeability to oil increased with increased rate.

These variations can possibly be explained by the Jamin effect[34]. At higher pressure drops the connate water held by capillary forces was forced to move, increasing the path available for flow. This is substantiated to some extent by the fact that, water cuts of about 2% were obtained in the primary production at higher rates and only a trace of water at lower rates.

The theory of Odeh[42] would not explain the relative permeabilities greater than one. Odeh suggested 1 Darcy as an upper limit to the permeability range in which viscosity influences relative permeability. Odeh's actual tests were made with viscosities of less than 100.

In an effort to explain the anomalous effective oil permeability, profiles were plotted for the tests at different temperatures. These are shown in Figure 7. While there was an apparent temperature effect between 100°F and 130°F the profile at 77°F did not confirm this.

Figure 8 shows two profiles obtained for identical conditions except direction of flow. These profiles were run primarily to see if there was any kind of saturation gradient inherent in the resaturation technique employed. The fact that the core was removed from the bath to turn it end for end and thereby allowed to cool and reheat may have in some way caused the very large shifts evident.

<u>Recovery</u>. Recoveries are summarized in Table I. The recovery histories are shown in Figures III-3, III-4 and III-5 of Appendix III. Test numbers 9 and 10 were run under the same conditions and give assurance of reasonably good reproducibility. Test number 14 run on pack number 6 gave recoveries in line with those of the previous pack when consideration was given to rate.

Test number 21 showed a lower breakthrough recovery than test number 20 run under identical conditions except for the direction of displacement. This may have been because the rate used for these tests was in the range where fingering was apparent. The good agreement between tests for the recoveries at a WOR of 5:1 suggested that the poor reproducibility of breakthrough recoveries might have been due to a rate induced instability.

TABLE I

SUMMARY OF DISPLACEMENT TEST CONDITIONS AND RESULTS

Test No.	Pack No.	Temp °F	Q cc/hr.	Initial Conds. S_w	K_o	K_{ro}	μ_o ave. Prior B.T.	Post B.T.	(μ_o/μ_w) ave.	Recovery I.O.I.P. B.T.	WOR 5:1
9	5	100	50	0.136	4.11	1.07	548	532	667	0.209	0.261
10	"	"	50	0.140	3.94	1.03	552	532	669	0.218	0.273
11	"	"	10	0.130	3.82	1.00	528	522	648	0.237	0.291
12	"	"	2.5	0.138	3.46	0.905	524	523	646	0.246	0.264*
13	"	"	80	0.138	4.17	1.09	565	537	680	0.178	0.241
14	6	"	30	0.131	3.40	0.939	544	530	663	0.224	0.279
15	"	77	"	0.131	3.30	0.912	1515	1410	1430	0.143	0.227
16	"	130	"	0.144	3.01	0.832	179	178	292	0.294	0.314
17	"	"	200	0.154	3.26	0.900	196	181	307	0.202	0.289
18	"	"	10	0.144	3.06	0.845	178	178	292	0.294	0.314
19	"	"	2.5	0.141	2.87	0.793	178	178	292	0.298	0.331
20	"	"	80	0.141	3.0	0.829	183	179	296	0.261	0.310
21**	"	"	"	0.144	3.23	0.892	"	"	296	0.214	0.306

* WOR 3.7
** Flow reversed for this test.

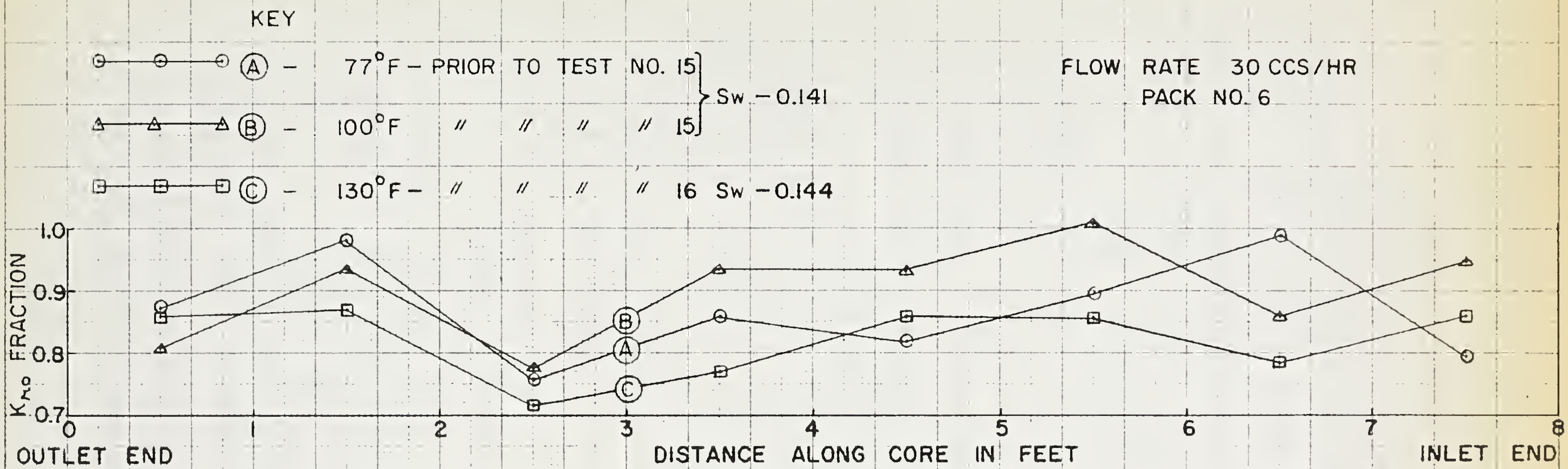


FIG. 7 RELATIVE PERMEABILITY PROFILES
AT DIFFERENT TEMPERATURES
AT INITIAL CONNATE WATER SATURATION

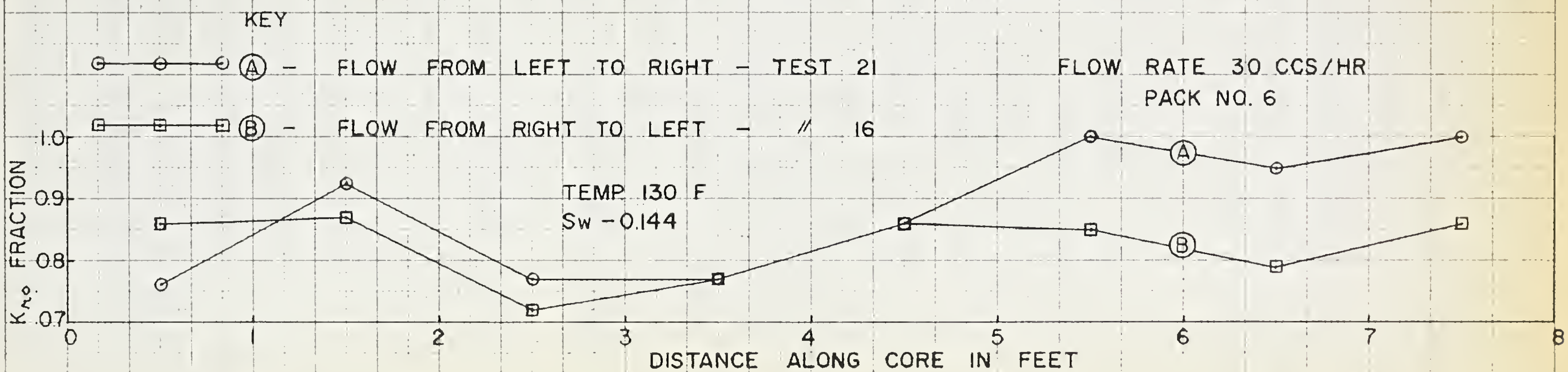


FIG. 8 RELATIVE PERMEABILITY PROFILES
FOR OPPOSITE DIRECTION OF FLOW
AT INITIAL CONNATE WATER SATURATION

Figure 9 shows the recovery efficiency as a function of the capillary scaling number. The injection rate is also shown in an approximate position along the horizontal axis. It may be observed that there is a decline in recovery with rate for the viscosity ratios of 292 and 646. For the viscosity ratio of 1430 only one rate was used.

Upon an examination of these results, two observations were made. Firstly, at low rates the recovery approached a constant value. Secondly the scaling number I at the lowest rate employed was approximately 0.05. This is less than the critical scaling number of 0.1 suggested by de Haan.

A point has been selected on each curve of the figure to represent the rate at which fingering has started to affect recovery. The selection of this point is very arbitrary. Chuoke's C value which corresponds to these selected points is 250 as indicated in Table 2. To give an idea as to the range of values which C could take, values have been calculated for all rates.

Figure 10 compares the recovery history of test number 9 of this work with that of a similar model from reference (5). There is a small difference in viscosity ratios between these tests. A higher breakthrough recovery was obtained in this work but further into subordinate production there is reasonable agreement. Test number 9 was affected by fingering. A comparison can also be made of the recoveries obtained in this work at a viscosity ratio of 292 with that of Newcombe et al[41].

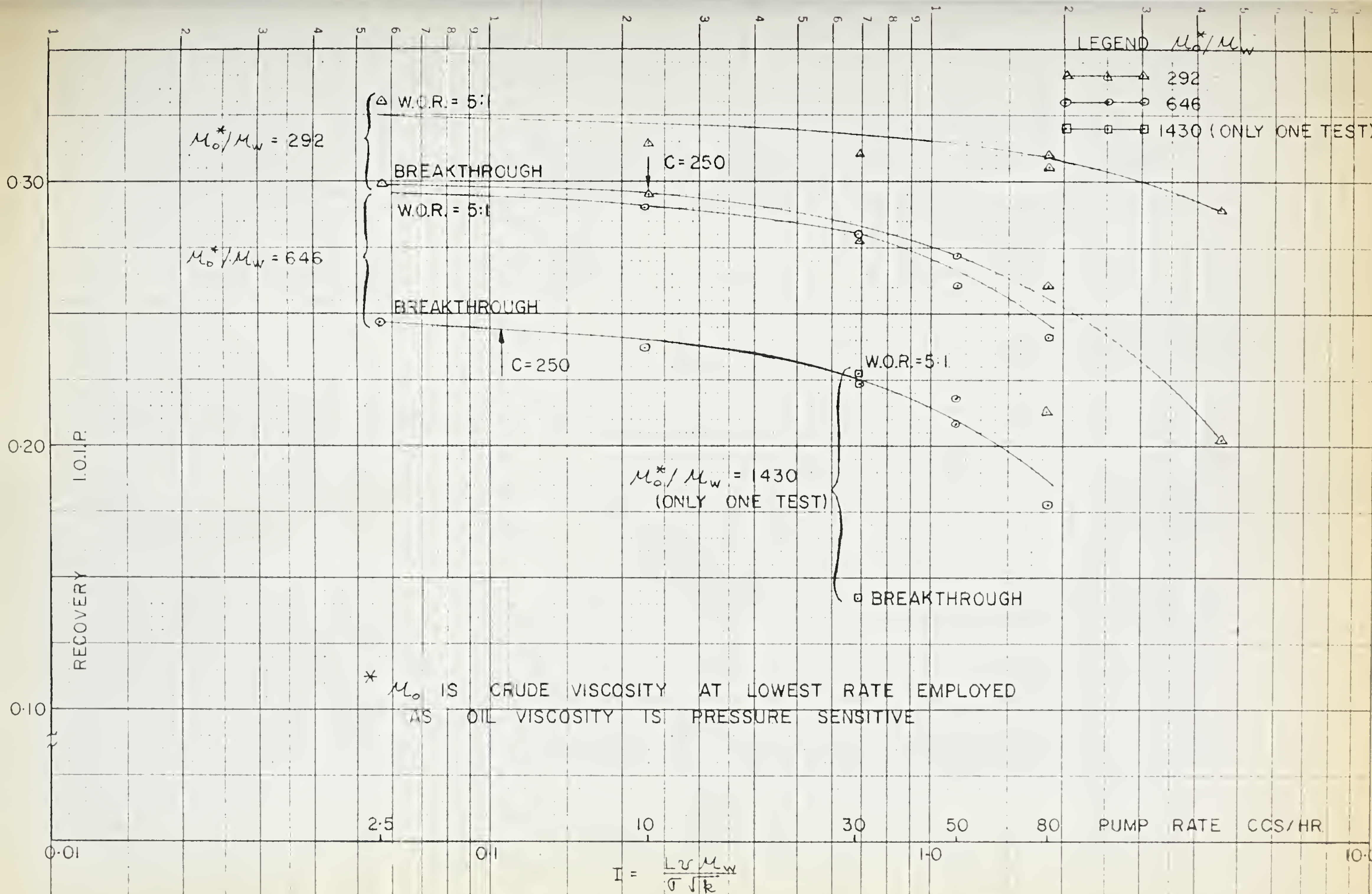
TABLE 2

CAPILLARY SCALING NUMBER AND VISCOUS FINGERING CONSTANT*

Temp °F	** μ_o/μ_w	μ_w ps.x10^2	σ $\frac{\text{dynes}}{\text{cm.}}$	K cm^2 x10^8	Q $\frac{\text{cm}^3}{\text{hr.}}$	v $\frac{\text{cm.}}{\text{sec.}}$	$I = \frac{Lv\mu_w}{\sigma\sqrt{K}}$	$C = \sqrt{\frac{3v(\mu_o-\mu_w)h^2}{\sigma K}}$	Recovery I.O.I.P. B.T.	Recovery I.O.I.P. WOR 5:1
100	646	0.81	11.0	3.77	2.5	$6.07\text{x}10^{-5}$	$5.61\text{x}10^{-2}$	182	0.246	---
100	648	0.81	11.0	3.77	10	$2.43\text{x}10^{-4}$	$2.25\text{x}10^{-1}$	365	0.237	0.291
100	663	0.81	11.0	3.57	30	$7.28\text{x}10^{-4}$	$6.92\text{x}10^{-1}$	631	0.224	0.279
100	667	0.81	11.0	3.77	50	$1.21\text{x}10^{-3}$	1.12	814	0.209	0.261
100	680	0.81	11.0	3.77	80	$1.94\text{x}10^{-3}$	1.80	1030	0.178	0.241
130	292	0.611	8.4	3.57	2.5	$6.07\text{x}10^{-5}$	$5.70\text{x}10^{-2}$	125	0.298	0.331
130	292	0.611	8.4	3.57	10	$2.43\text{x}10^{-4}$	$2.28\text{x}10^{-1}$	250	0.294	0.314
130	292	0.611	8.4	3.57	30	$7.28\text{x}10^{-4}$	$6.83\text{x}10^{-1}$	433	0.277	0.311
130	296	0.611	8.4	3.57	80	$1.94\text{x}10^{-3}$	1.82	707	0.214	0.306
130	296	0.611	8.4	3.57	80	$1.94\text{x}10^{-3}$	1.82	707	0.261	0.310
130	307	0.611	8.4	3.57	200	$4.85\text{x}10^{-3}$	4.56	1120	0.202	0.289
77	1430	1.023	14.0	3.57	30	$7.28\text{x}10^{-4}$	$6.90\text{x}10^{-1}$	1310	0.143	0.227

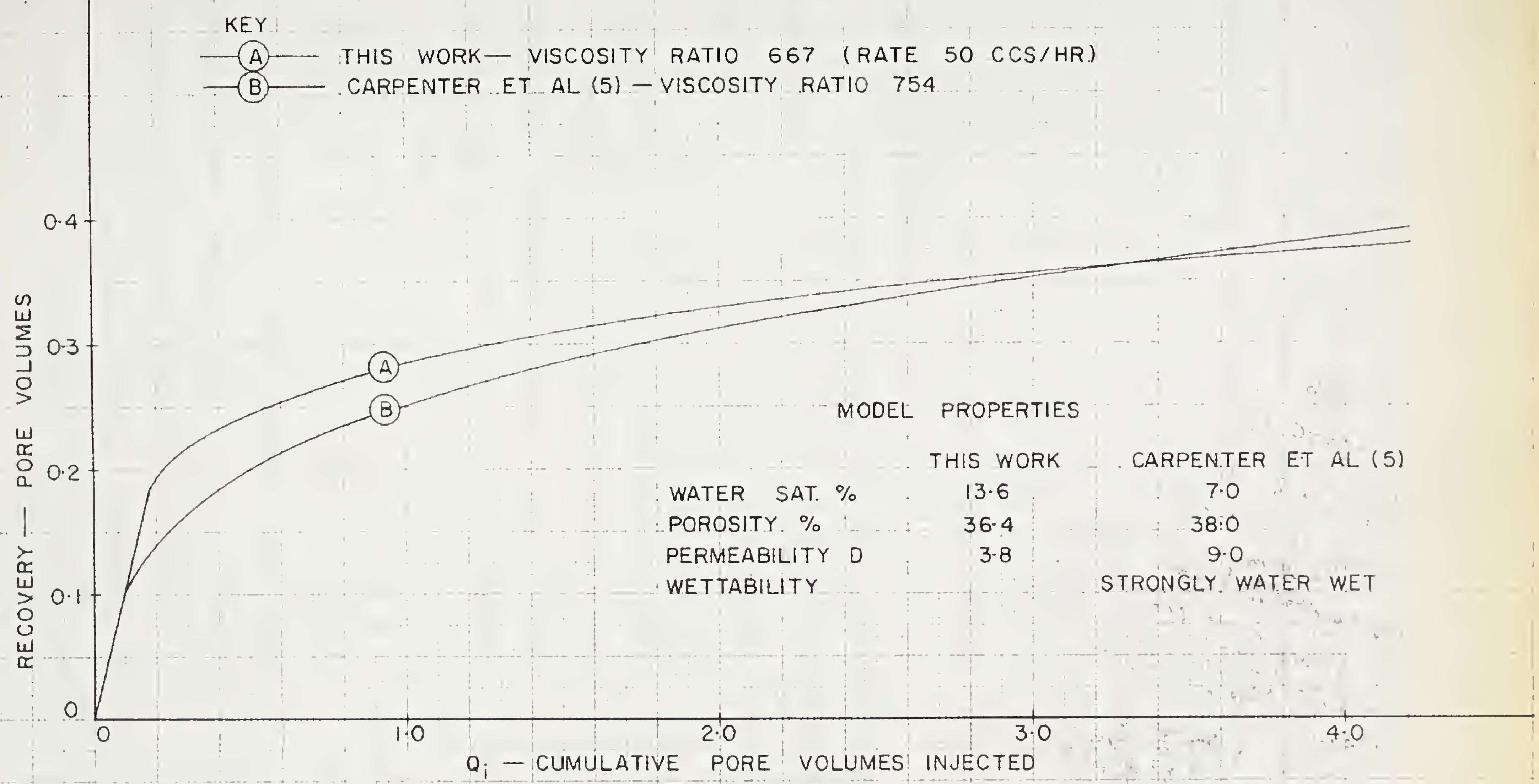
* Only one value of constant can actually apply to system. Listed values are those that would apply if onset of fingering coincided with that particular rate. Tentative value chosen for system is 250.

** Average value.



* $\mathcal{M}_o$ IS CRUDE VISCOSITY AT LOWEST RATE EMPLOYED AS OIL VISCOSITY IS PRESSURE SENSITIVE

FIG. 9 DISPLACEMENT EFFICIENCY AS A FUNCTION OF RATE



FIG· 10 COMPARISON OF RECOVERY DATA FOR TEST NO·9 OF THIS WORK WITH UNCONS: SAND MODEL OF CARPENTER ET AL (5)

Evidence of Fingering. The recovery curves shown in Figure 9 are similar to those of de Haan[13] except that in the work of the latter a stable region of fully developed fingering was reached. If we assume that stability is attained at an h/λ_m value of five or six, a rate twenty-five to thirty-six times the critical would be required to achieve fully developed fingering. This rate would have exceeded the pressure for which the core holder was designed. Had this been possible it might have given some support for Chuoke's theory as opposed to some other effect.

In an effort to further analyze the fingering mechanism the data were plotted to provide fractional flow curves, pressure profiles, injectivity histories etc.

The fractional flow curves obtained are shown in Figures 11 and III-1. If there were no rate effect, all curves obtained at the same viscosity ratio should reproduce themselves. This was not the case. Figure 11 shows that higher rates favored a higher water fraction flowing. It was noted that all curves extrapolated to $f_w = 0$ at a water saturation between 11% and 13% which is a reasonable confirmation of the irreducible water saturation. The lowest rate extrapolated to the highest water saturation in line with previous comments on the Jamin effect but the trend was not definitely established at all rates.

The pressure profiles provided an excellent picture of the effect of fingering on the saturation distribution

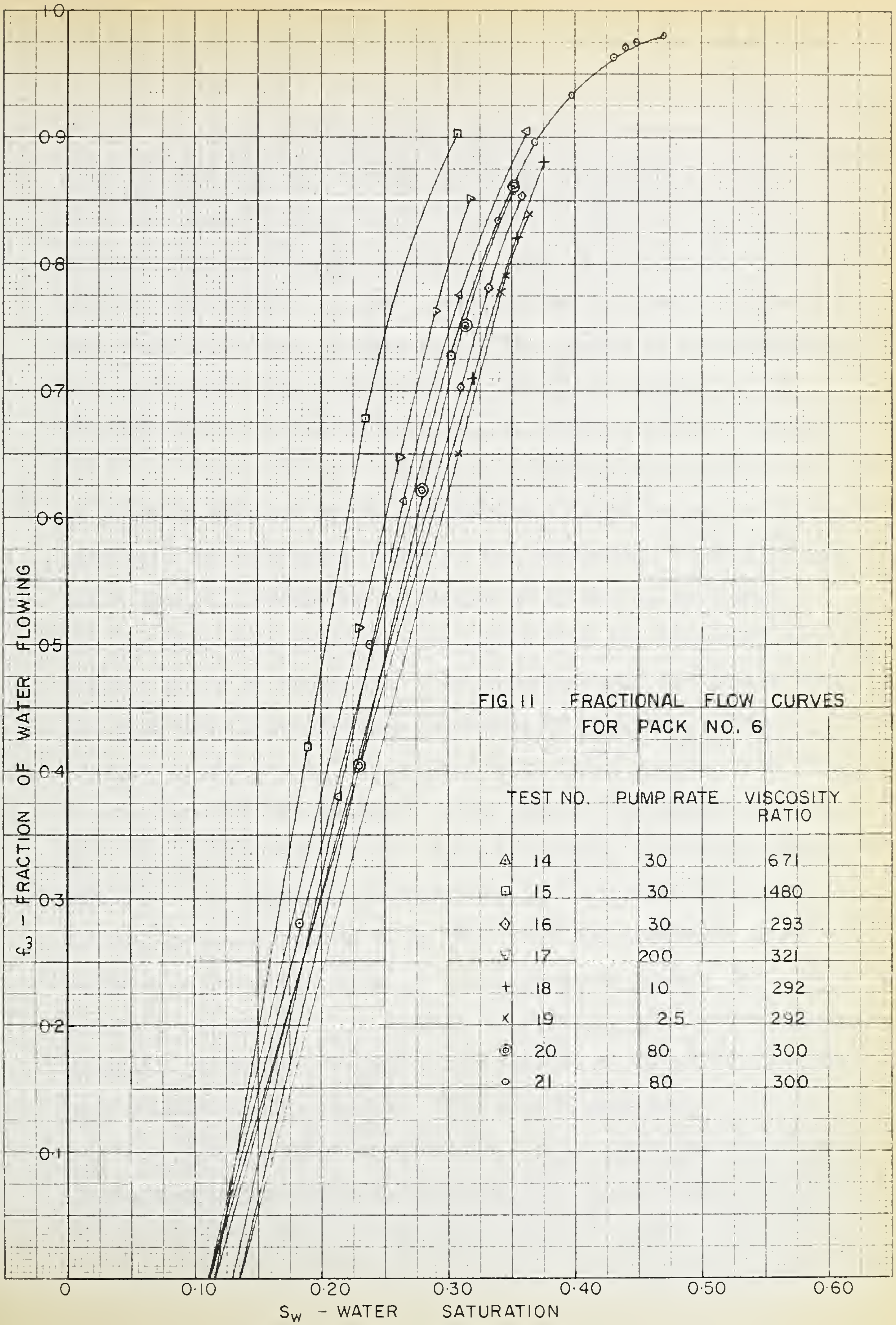


FIG. 11 FRACTIONAL FLOW CURVES FOR PACK NO. 6

TEST NO.	PUMP RATE	VISCOSITY RATIO
△ 14	30	671
⊡ 15	30	1480
◇ 16	30	293
▽ 17	200	321
+ 18	10	292
× 19	2.5	292
⊚ 20	80	300
○ 21	80	300

within the core. A convenient presentation was obtained by plotting the pressure drop in terms of the inverse of the relative injectivity. The influence of rate and viscosity on the pressure distribution at a stage before breakthrough is shown in Figures 12 and 13 respectively. Similar curves are shown in Figures 14 and 15 at the instant of breakthrough. It may be noted that the profiles tended to flatten out at high rates and viscosity ratios, indicating viscous fingering.

The effect of fingering on displacement efficiency is shown in another way by plotting the injectivity history with rate and viscosity ratio as the parameters in Figures 16, III-5 and 17. Referring to Figure 16 it can be seen that the low rate injectivities were lower than the high-rate injectivities prior to the approach of breakthrough, but higher than the high rate injectivities following breakthrough. The anomaly of the lowest-rate injectivity being greater than one, at the start of displacement, required an explanation. This was believed due to the fact that as soon as the displacement commenced the measured pressure drop ΔP differed from the initial pressure drop ΔP_i by the capillary pressure. The value used for the initial pressure drop was always that obtained for oil flow at connate water saturation. The actual pressure attributed to capillary pressure of about 5.5 psi was only significant at the very lowest rate employed.

In an effort to evaluate a possible relation between finger growth and the distance travelled by the front along the

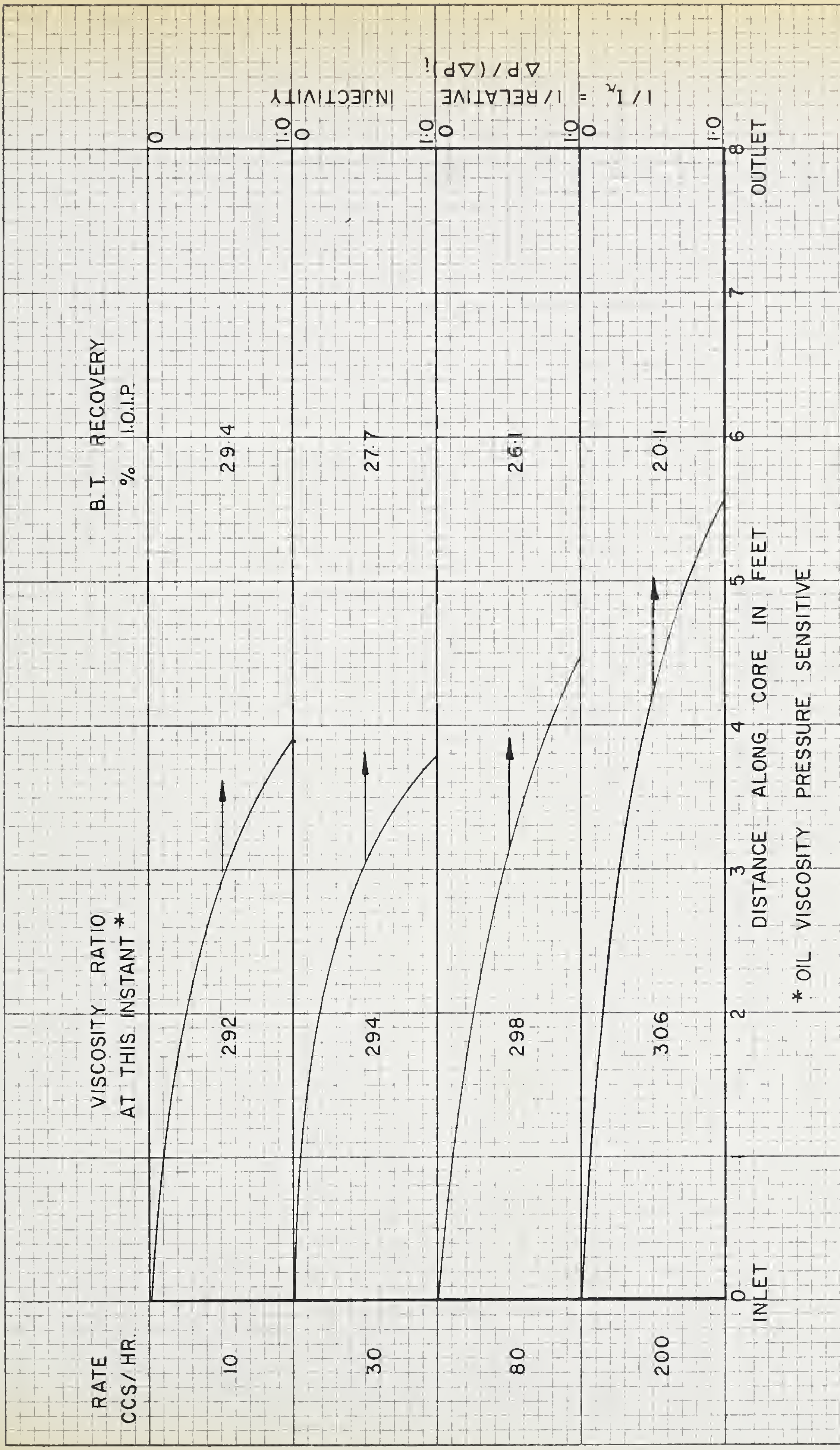


FIG. 12 PRESSURE PROFILE FOR VARIOUS INJECTION RATES AT 0.100 PORE VOLUMES BRINE INJECTED

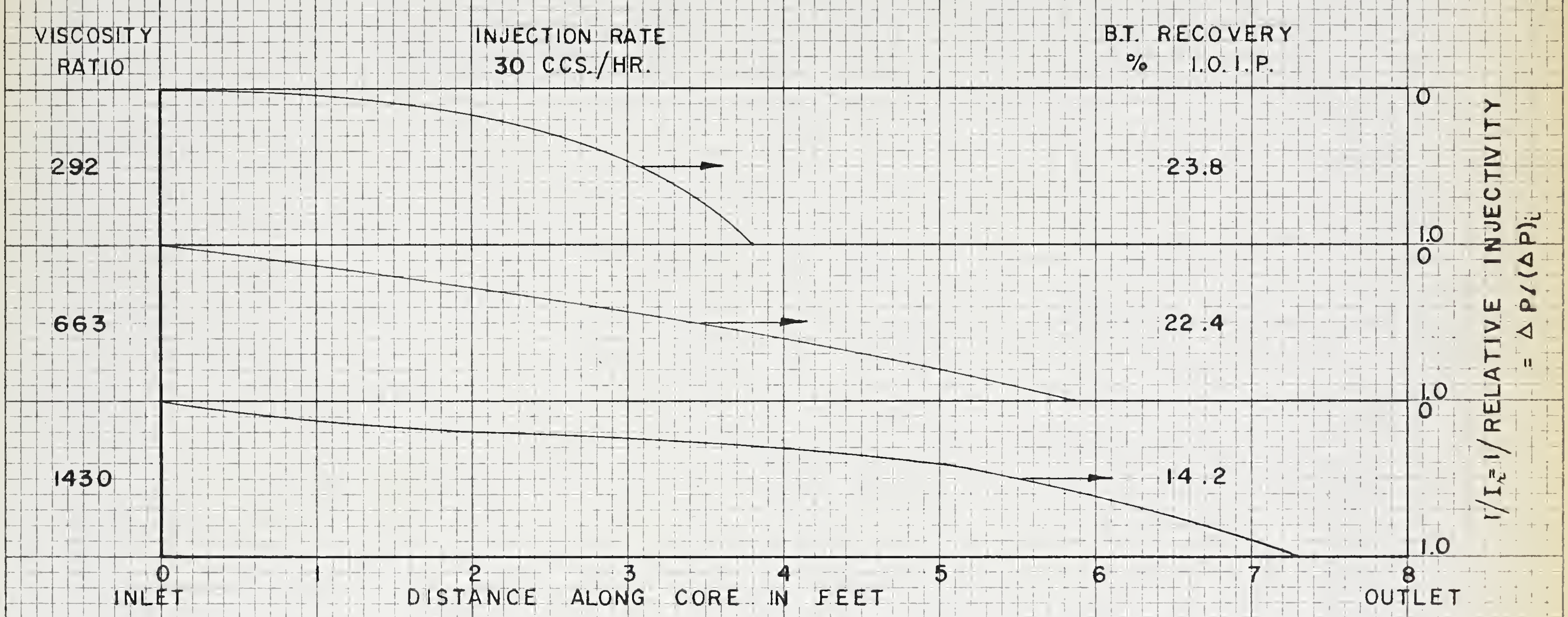


FIG. 13 PRESSURE PROFILE FOR DIFFERENT VISCOSITY RATIOS AT 0.100 PORE VOLUMES BRINE INJECTED.

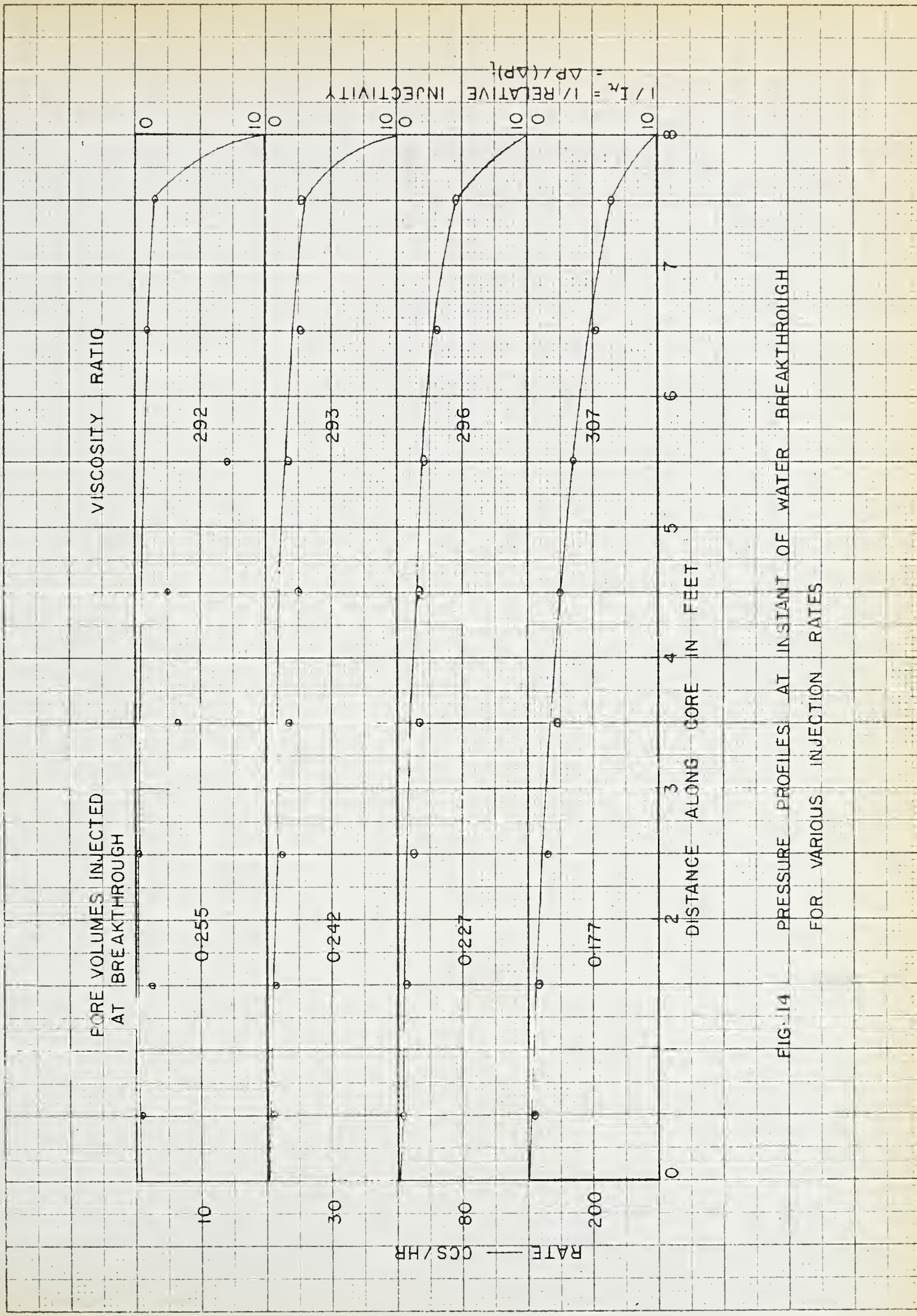


FIG. 14 PRESSURE PROFILES AT INSTANT OF WATER BREAKTHROUGH FOR VARIOUS INJECTION RATES

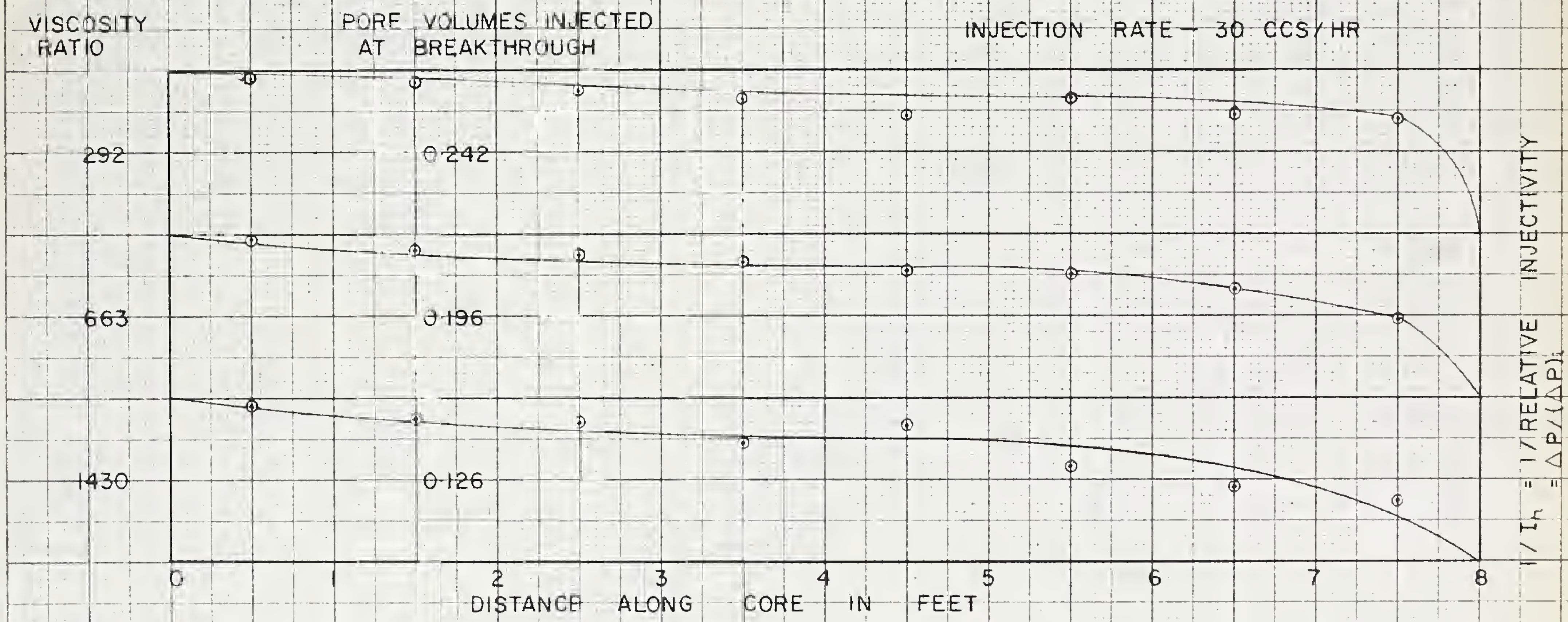
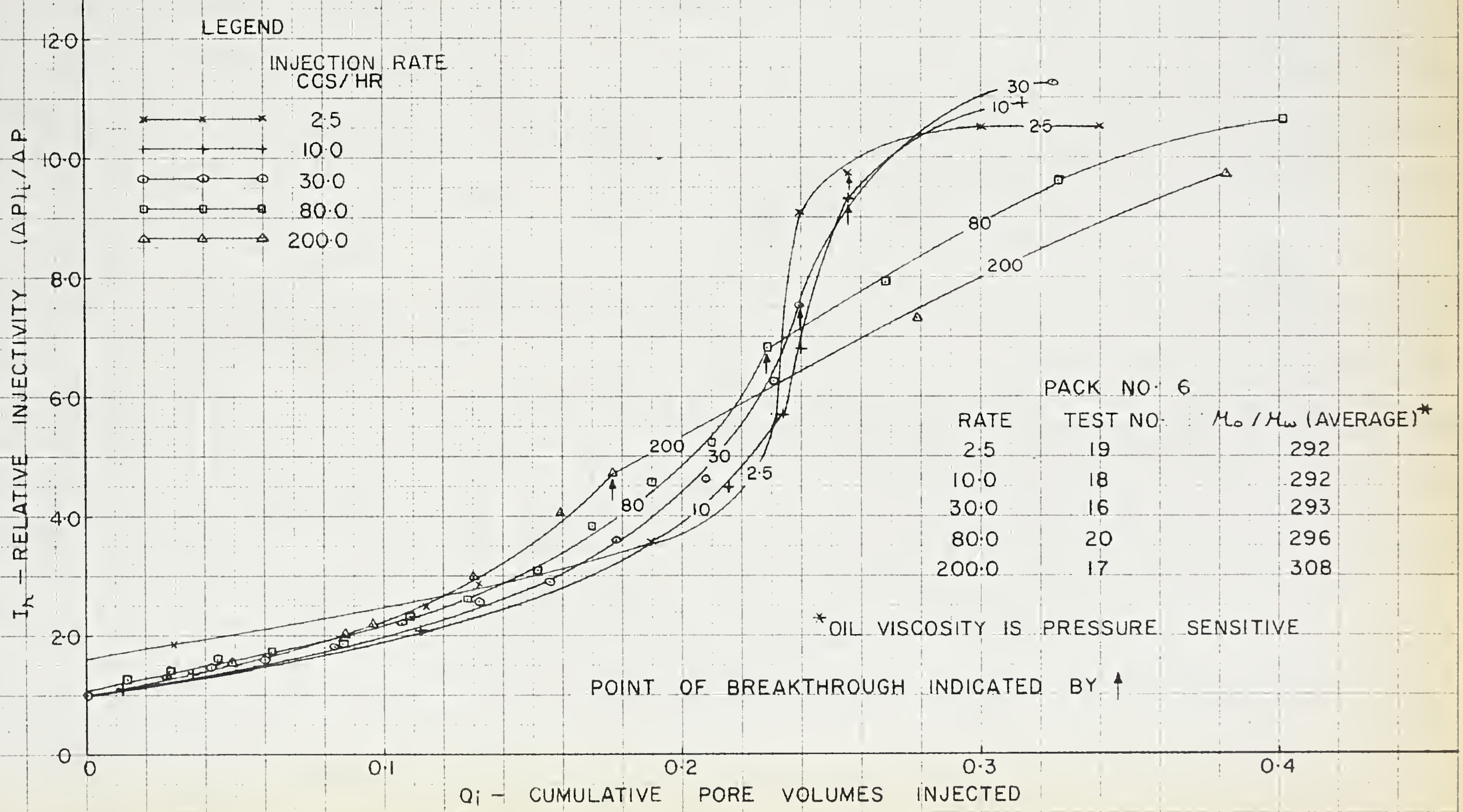


FIG 15 PRESSURE PROFILES AT INSTANT OF WATER BREAKTHROUGH FOR THREE VISCOSITY RATIOS (μ_o/μ_w)



FIG· 16 EFFECT OF INJECTION RATE ON RELATIVE INJECTIVITY

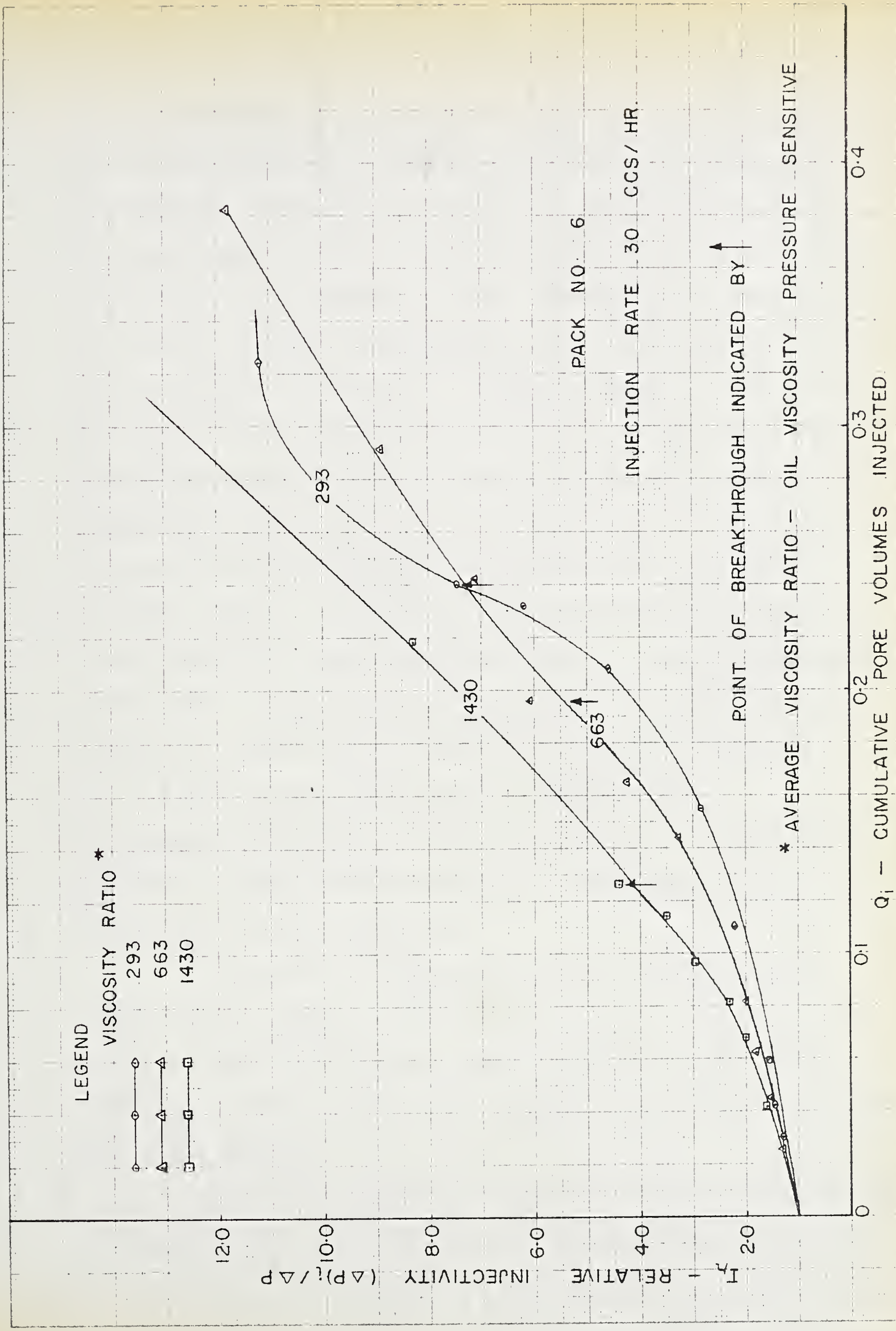


FIG. 17 EFFECT OF VISCOSITY RATIO ON RELATIVE INJECTIVITY

core, hypothetical breakthrough recoveries were calculated which were based on the pressure profiles. Hypothetical breakthrough recovery is that which would be obtained if the core length coincided with the position of the front as revealed by the pressure profile. Partial pore volumes were calculated assuming a homogeneous pack. The result of this study is shown in Figure 18. Although there is considerable scatter a general trend can be observed toward higher breakthrough recovery as the front progressed. It appeared that finger growth was not accelerating but rather stabilizing. Because maximum breakthrough recoveries were obtained at the full length of the model it was concluded that still higher recoveries might be obtainable in a core longer than eight feet. It was not obvious whether rate could be established as a parameter in Figure 18 although there was a general trend toward stability at lower rates.

Subordinate Production. The subordinate production data was analyzed to determine the effect of fingering, if any, on production after breakthrough.

An example of pressure profiles obtained after breakthrough is shown in Figure 19. It was noted that the first two profiles obtained following breakthrough still exhibited a frontal appearance normally associated with a high saturation gradient.

Following a procedure similar to that used by Loomis and Crowell[36] a plot was made of f_o against Q_i on semi log

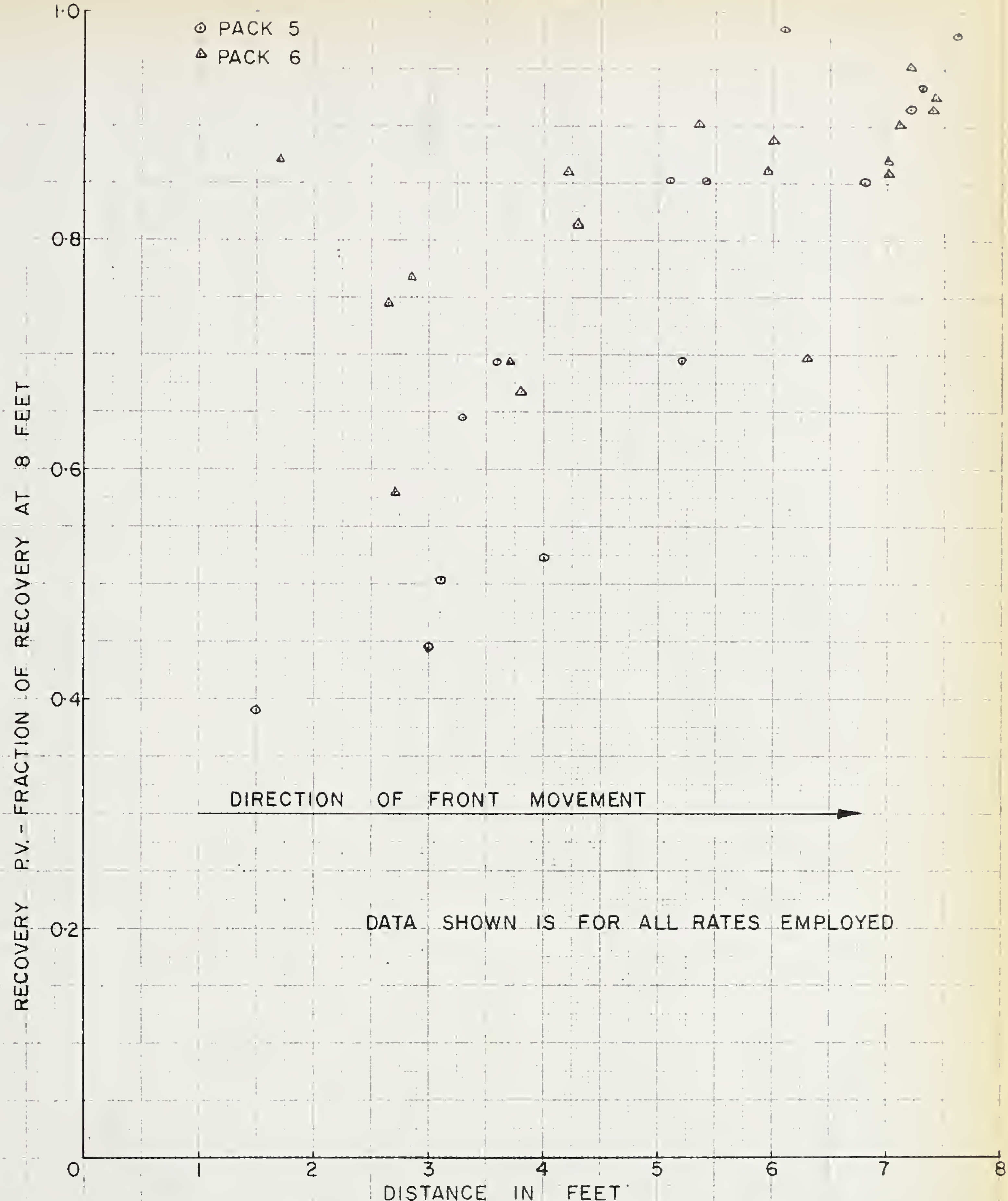


FIG. 18 HYPOTHETICAL BREAKTHROUGH RECOVERY AS A FUNCTION OF DISTANCE TRAVELLED ALONG CORE BASED ON PRESSURE PROFILES.

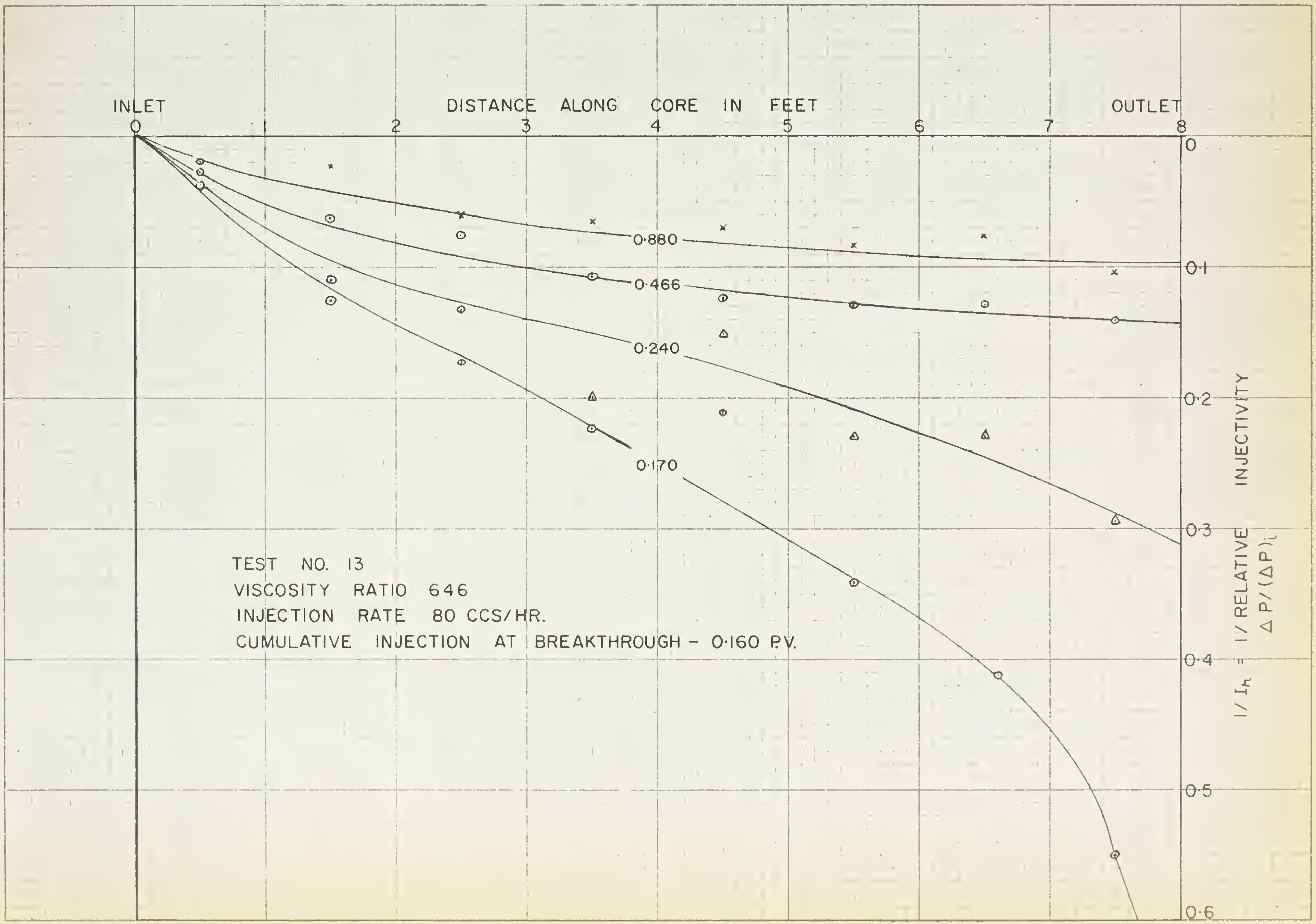


FIG. 19 EXAMPLE OF PRESSURE PROFILES AT VARIOUS CUMULATIVE P.V.'S INJECTED AFTER BREAKTHROUGH

paper as shown in Figure 20. No theoretical basis can be given to justify the interpretation of a linear plot indicated. This is a constant rate of decline which sometimes is actually observed in fields(27). The purpose of this plot was to determine a cut off for rejecting data which might be influenced by a saturation gradient. The existence of an associated capillary pressure gradient negates the application of the simplified fractional flow formula in computing relative permeability ratios.

Loomis and Crowell were concerned with the existence of the "stabilized zone"(36). This is the region in which capillary and viscous forces are postulated to be in balance. In this work the existence of a stabilized zone would not be expected except possibly at the very lowest rate. The "frontal zone" of Figure 20 is interpreted to be a dispersed zone of high water saturation somehow related to fingering. Unfortunately only four of the tests were carried to high enough water oil ratios to permit analysis of the subordinate production beyond the "frontal zone".

Theoretical Recovery. In order to determine whether the recoveries obtained in this work could be predicted by Buckley-Leverett theory relative permeability ratios were required. The use of the unsteady state relative permeability data as shown in Figure 5 was not entirely justified because those data were derived assuming Buckley-Leverett theory did apply. The steady state relative permeability data obtained

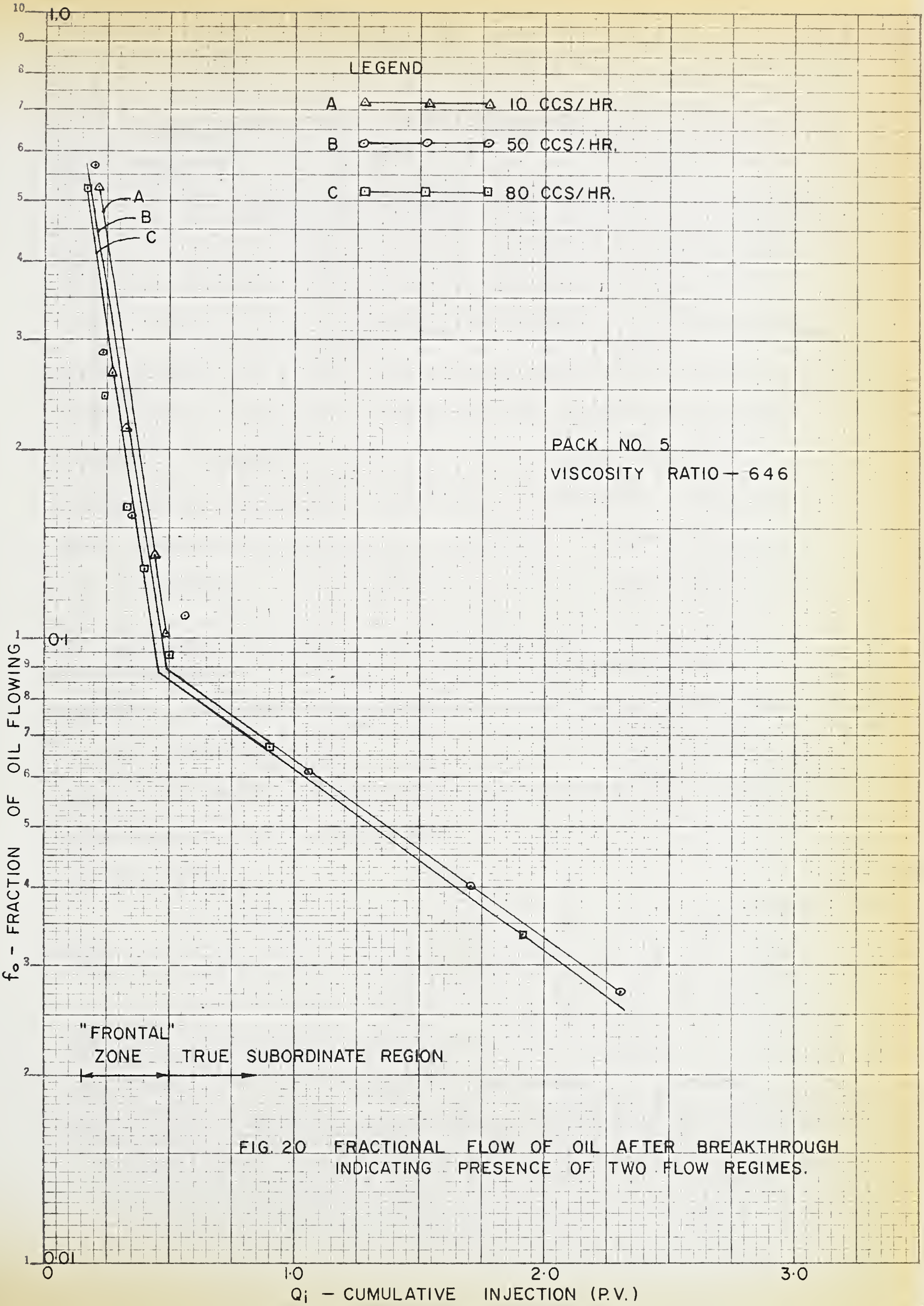


FIG. 20 FRACTIONAL FLOW OF OIL AFTER BREAKTHROUGH INDICATING PRESENCE OF TWO FLOW REGIMES.

as shown in Tables II-1 to II-4 of Appendix II were therefore obtained.

The theoretical recovery as a function of viscosity ratio is shown in Figure 22. The recoveries were obtained from the fractional flow curves constructed in Figure 21.

Because the steady state relative permeability data did not extend to a high enough saturation range it was necessary to construct a composite curve based on all data as shown in Figure 23. The use of this composite relative permeability ratio curve resulted in theoretical recoveries less than actually obtained in the tests. However this was not considered to be an indication of the inapplicability of Buckley-Leverett theory to this case. It was found that theoretical recoveries were extremely sensitive to the position and shape of the relative permeability ratio curve in this saturation range. The difference between actual and theoretical recoveries can therefore be explained by experimental error of a magnitude which is suggested by the spread of data points.

To further evaluate the relative permeability data they are compared with those of Leverett in Figure 24. The unsteady state relative permeability ratios were converted to effective permeabilities by the method of Johnson, Bossler and Naumann[25]. An example of this method is given in Table III-27. Values for the relative permeability to water

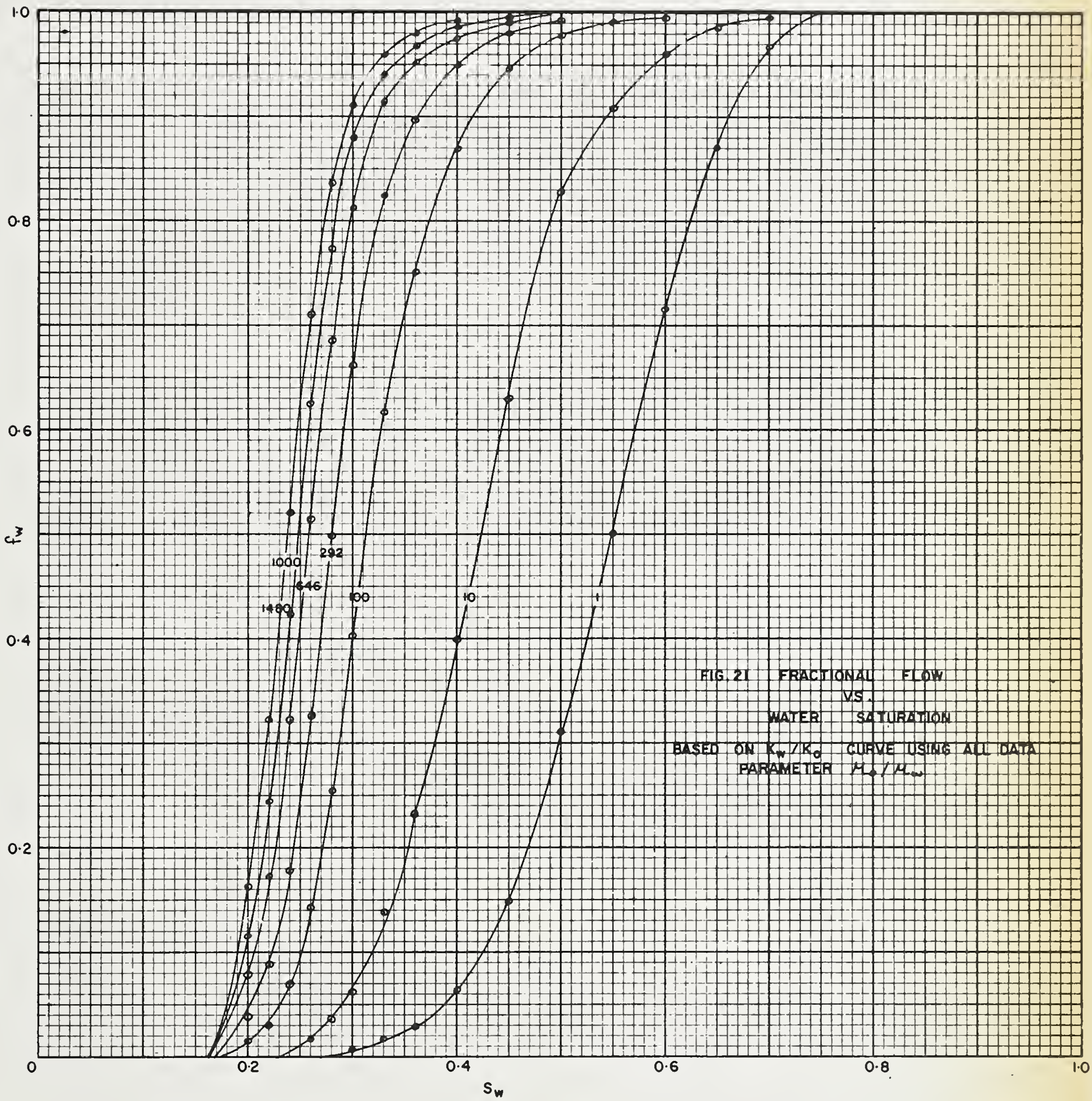


FIG. 21 FRACTIONAL FLOW
VS.
WATER SATURATION
BASED ON K_w/K_o CURVE USING ALL DATA
PARAMETER μ_o/μ_w
f_w
S_w
1400
1000
646
292
100
10
1
0
0·2
0·4
0·6
0·8
1·0

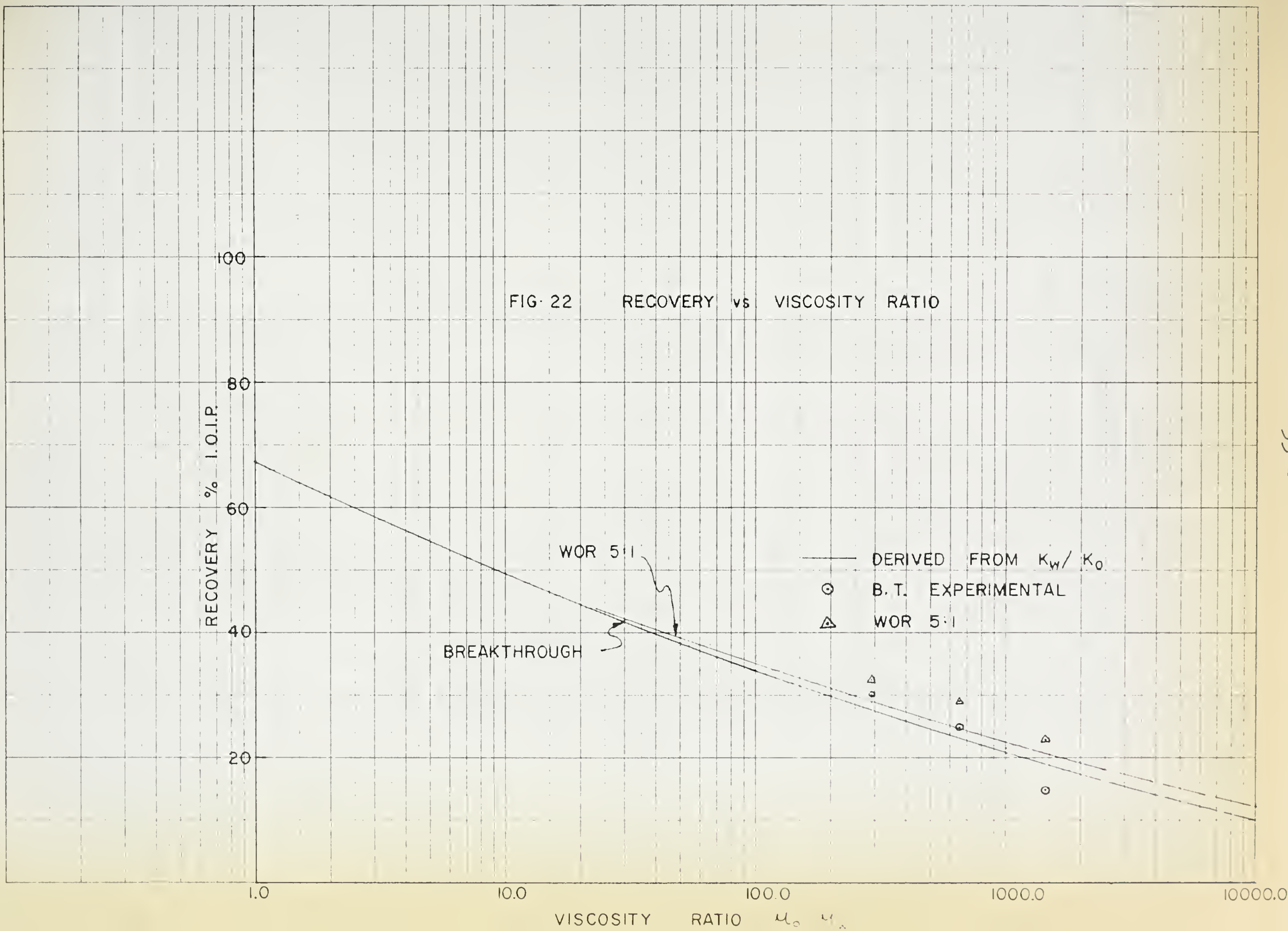


FIG. 22 RECOVERY vs VISCOSITY RATIO

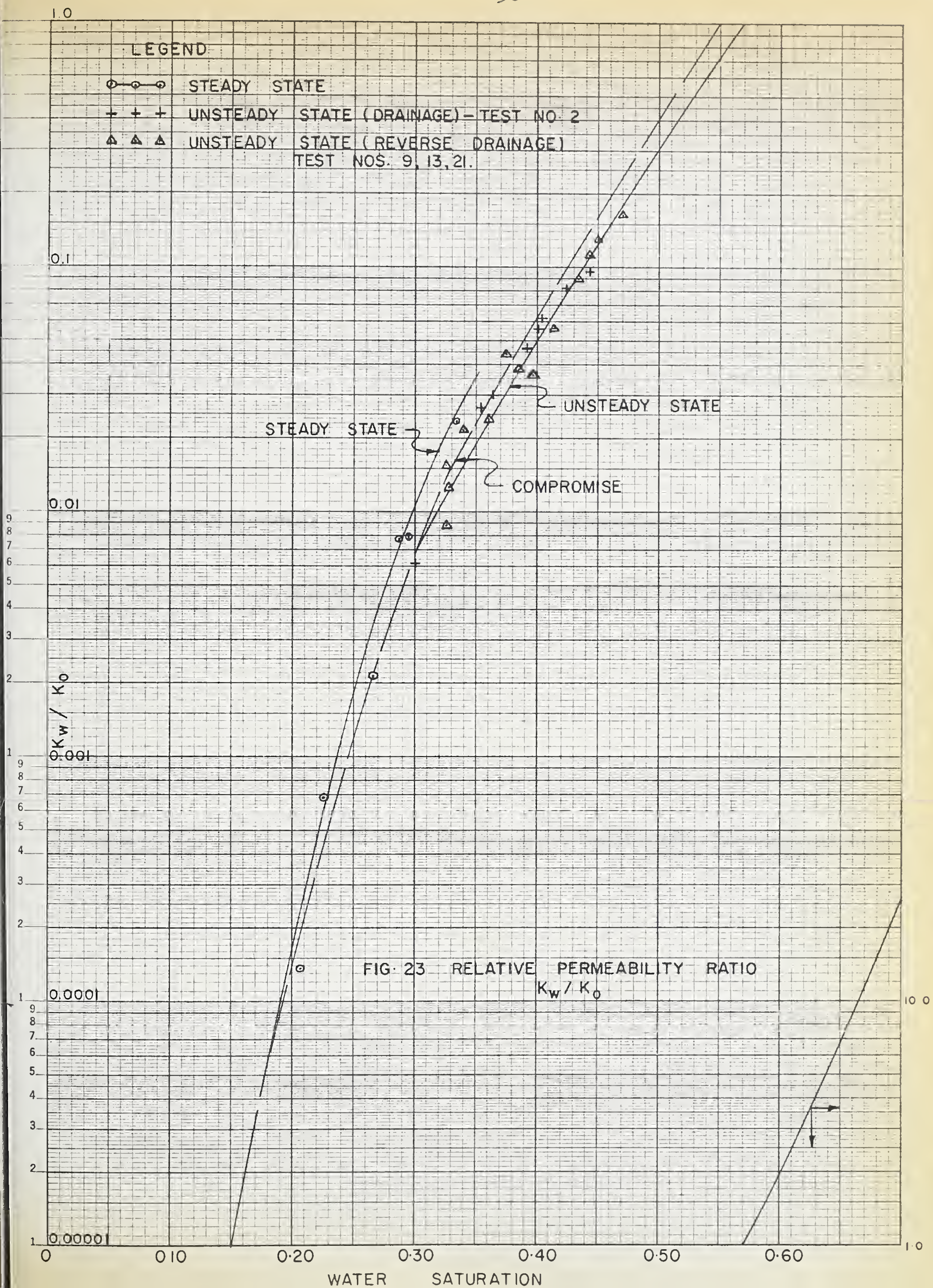


FIG. 23 RELATIVE PERMEABILITY RATIO K_W / K_O

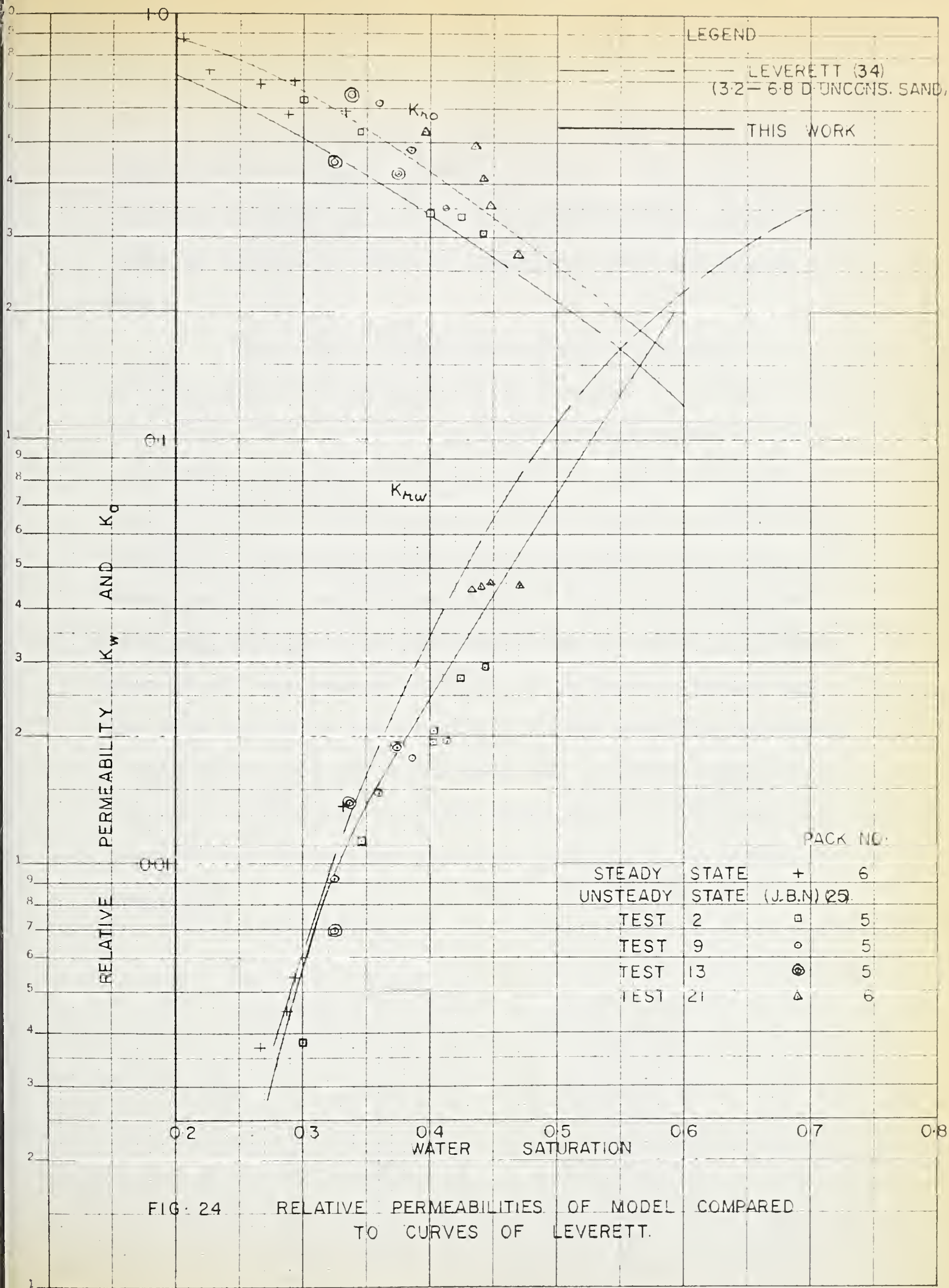


FIG. 24 RELATIVE PERMEABILITIES OF MODEL COMPARED TO CURVES OF LEVERETT.

for this work are slightly lower than those of Leverett, particularly the unsteady state points. The values of relative permeability to oil are significantly greater than those of Leverett. This is compatible with the theory of Odeh.

Theoretical recoveries based on Leverett's relative permeabilities are lower than those obtained from this work. This is shown in Table 3 which compares the recoveries cited in the literature for various viscosity ratios with the ones derived from these data. Recoveries obtained in this work were generally higher than those of other workers. Recoveries obtained by Kyte and Rapoport were significantly higher however and it may be pertinent that of all the papers referred to in Table 3 theirs was the only one which was cognizant of the possible existence of fingering. On the other hand the recoveries shown for Fatt and Klikoff and Leverett were derived from their relative permeability curves and therefore should not be influenced by fingering.

TABLE 3

COMPARISON OF EXPERIMENTAL RECOVERIES GIVEN IN LITERATURE WITH THEORETICAL RECOVERIES FROM THIS WORK

Source	System Properties (All strongly Water wet)	Length cm. / $\frac{L V \mu_w}{cm.^2 cp.}$ min.	Viscosity Ratio	Recovery % I.O.I.P. Other Works B.T.	Other Works WOR 5:1	This Work (From Fig.) B.T.	This Work (From Fig.) WOR 5:1
Carpenter et al (5)	Uncons.Sand S_c - 0.07 Ø-0.38 K.9.0D	30.5 -	141	26	34	32	33
Carpenter et al	Uncons.Sand S_c - 0.07 Ø-0.38 K.9.0D	30.5 -	754	11	20	22	24
Leverett (34)	Uncons.Sand S_c - 0.14 Ø-0.41 K-5.ID	Press. Grad. 3.3psi/ft	90	28*	33*	34.5	36
Fatt & Klikoff (18)	Uncons.Sand K-3.18D	30.5 4.87	100	33**	42**	34	35
Felsenthal (19)	Cons.Sand S_c - 0.275 Ø-0.248K420md	28.6 P.Grad. 37.4psi/ft	95.4	30	32	34	36
Fried (20)	Alundum S_c - 0.21 Ø-0.248K-300md	12.5 1.15	141.7	9	21	32	33
Kyte & Rapoport (32)	Alundum S_c - 0.0 Ø-0.240K-574md	32.8	102	49	52	34	35
This Work	Uncons.Sand S_c - 0.14 Ø-0.345K-3.62D	244 $\geq$ 0.54					

* Derived from fractional flow curve.
** Derived from K_w/K_o curve.

CONCLUSIONS

The following conclusions were made on the basis of the test results.

1. Breakthrough recoveries of 24.6% and 29.8% of initial oil in place were obtained at viscosity ratios of 646 and 292 respectively.
2. Actual breakthrough recoveries obtained were higher than those predicted by Buckley-Leverett theory. The discrepancy between theoretical and observed recoveries was believed to be due to the extreme sensitivity of theoretical recovery to small changes in the relative permeability ratio through the range of low water saturation involved.
3. There was some evidence that higher recoveries would be possible with a longer model.
4. Breakthrough recovery was found to be sensitive to the rate of displacement. High rates had a detrimental effect on displacement efficiency. At lower rates the influence diminished. This rate effect was attributed to viscous fingering and with reference to the theory of Chuoke a C value of 250 was tentatively assigned to the model to establish the point of onset of fingering.
5. Subordinate production was divided into two flow regimes. The first regime was that consisting of a fairly large oil fraction which came immediately after breakthrough. The

second was that of a smaller oil fraction which declined at a constant rate. Only production in the second regime was used to calculate unsteady state relative permeabilities because of the high saturation gradients associated with the first regime.

6. The sand used in the tests was found to be preferentially water wet and its wettability remained unchanged during the tests.
7. The high viscosity ratio was unfavorable to the oil mobility. This, combined with the saturation change accompanying the passage of the front resulted in a sharp loss of oil mobility behind the front.
8. The "wet" sand packing procedure resulted in a model of variable permeability throughout its length. The permeability increased toward the base of the pack.
9. The variations in model properties between the two packs did not appear to have influenced recoveries.
10. In the crude oil viscosity range of 170 cp. to 1500 cp. original brine saturations were restored at the conclusion of a displacement by injecting as little as one pore volume of crude.
11. Using this resaturation technique as opposed to cleaning, drying and resaturating, in conjunction with viscosity ratio control by varying temperature reduced the time between tests from about one week to one day.

RECOMMENDATIONS

Before an attempt is made to transfer the behavior of this model to other systems, some verifying tests should be run. An attempt should be made to further examine the effect of rate on the oil permeability at initial connate water saturation in the absence of disturbing factors such as temperature change, variable interfacial tension, and corrosion. Due to the scarcity of correlative evidence from other unconsolidated sand models, the possible influence of those variables unique to this model cannot be discounted.

These factors could all be controlled using the same model in the following way. The same sand could be initially treated more extensively to render it water wet. The use of an additive to the brine such as sodium tripolyphosphate[24] would help reduce the corrosion and at the same time preserve the water wetness of the system[23]. By using an artificial brine and a blend of refined mineral oils the interfacial tension could be controlled. The tests could be run at constant temperature at a viscosity ratio determined by blending.

The selection of the rate of injection should be based on the rate studies of this thesis with reference to the particular viscosity ratio employed.

All future displacement tests should be carried to a water to oil ratio of at least ten to one. Subordinate

production data should be analyzed in an attempt to determine if the point of separation between the primary and subordinate phases is really breakthrough, or some time later in the displacement history.

A study should be conducted on the effect of length on recovery in the viscosity range under study. To increase the model length significantly, a length of thirty or forty feet might be considered. Pressure taps could be placed at the ends only but provision could be made to measure the pressure in each phase for low rate studies.

End faces should be designed to permit flow both through and across the entire end of the core. This would appear to be of increasing importance as the model diameter to length ratio increases.

PRACTICAL APPLICABILITY

The results of this work indicate that conventional water flooding may be attractive in systems similar to the model in the viscosity range of 100 to 1000 centipoise or even higher. However the unfavorable mobility ratio associated with the subordinate production is related to high injectivities after breakthrough. Homogeneity of the reservoir is therefore a property which should be investigated thoroughly prior to flooding. If stratification exists, any success in counteracting bipassing would probably yield a more dramatic improvement in recovery than viscosity reduction alone.

NOMENCLATURE

A –	cross sectional area (cm^2)
C –	constant
f_o –	fraction of oil flowing at any point
f_w –	fraction of water flowing at any point
I –	capillary scaling number
I.O.I.P. –	initial oil in place
K –	absolute permeability (darcies)(cm^2)
K_w, K_o –	effective permeability to water and oil respectively (darcies)
k_w, k_o –	relative permeabilities to water and oil respectively
L –	length (cm)
$Lv\mu_w$ –	scaling coefficient $\left(\frac{cm^2 cp}{min}\right)$
λm –	average distance between fingers (cm)
λcr –	critical wavelength (cm)
ϕ –	porosity
P.V. –	pore volume (fraction)
P_c –	capillary pressure (atm)
ΔP –	differential pressure (psig)
$(\Delta P)_i$ –	differential pressure at start (psig)
Q_i –	cumulative injection (P.V.)
q_t –	total flow rate (cc/sec)
S_w –	water saturation (fraction)
S_{w_c} –	connate water saturation (fraction)

μ_o - oil viscosity (cp)(ps)

μ_w - water viscosity (cp)(ps)*

σ - surface tension (dynes/cm)

v - total flow rate per unit cross sectional area (cm/sec)

WOR - water oil ratio

* where two units are given the second unit applies to finger scaling theory.

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APPENDIX I

TABLE I-1

ANALYSIS OF RESERVOIR WATER

Appearance of Sample: Clear liquid
Small amount of rust-colored sediment

	Mg per liter	Percent of Calculated Solids
Cl	51,467	61.8
CO_3	0	0.0
HCO_3	118	0.2
SO_4	2	0.0
OH	0	0.0
Br	195	0.2
I	12	0.0
Ca	3,540	4.3
Mg	1,681	2.0
Na*(Calc)	26,243	31.5
Total Solids (Calc)	83,258	100.0

* Alkali metals calculated as Na.

Density, 60°F	1.0583
pH	6.2
H_2S	None
Resistivity, ohm-meters, 25°C	0.101
Ref. Index, 25°C	1.3469
Total Solids	
evap. at 110°C	83,470
evap. at 180°C	83,090
after ignition	81,830

Remarks: Fe-some

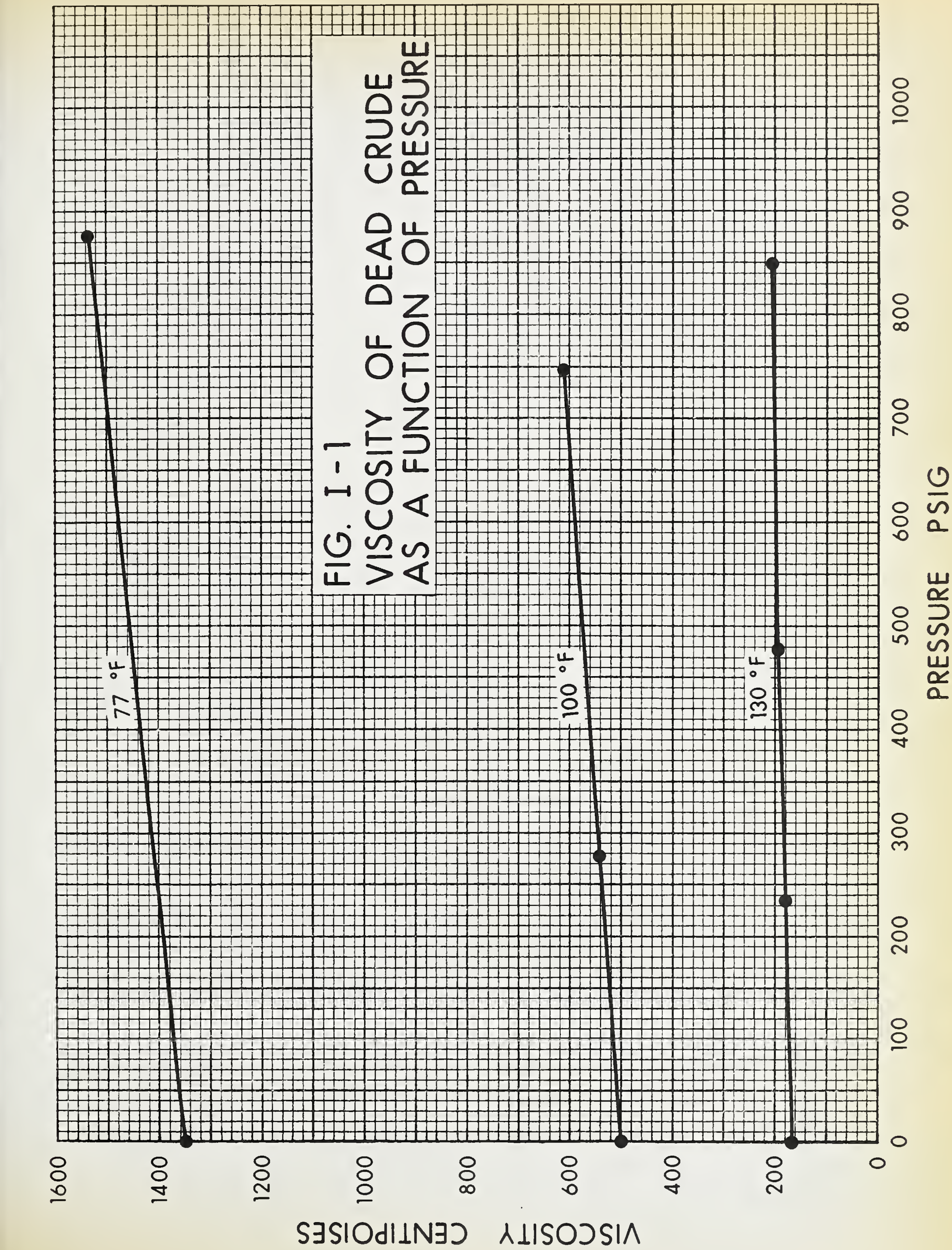

FIG. I-1
VISCOSITY OF DEAD CRUDE
AS A FUNCTION OF PRESSURE

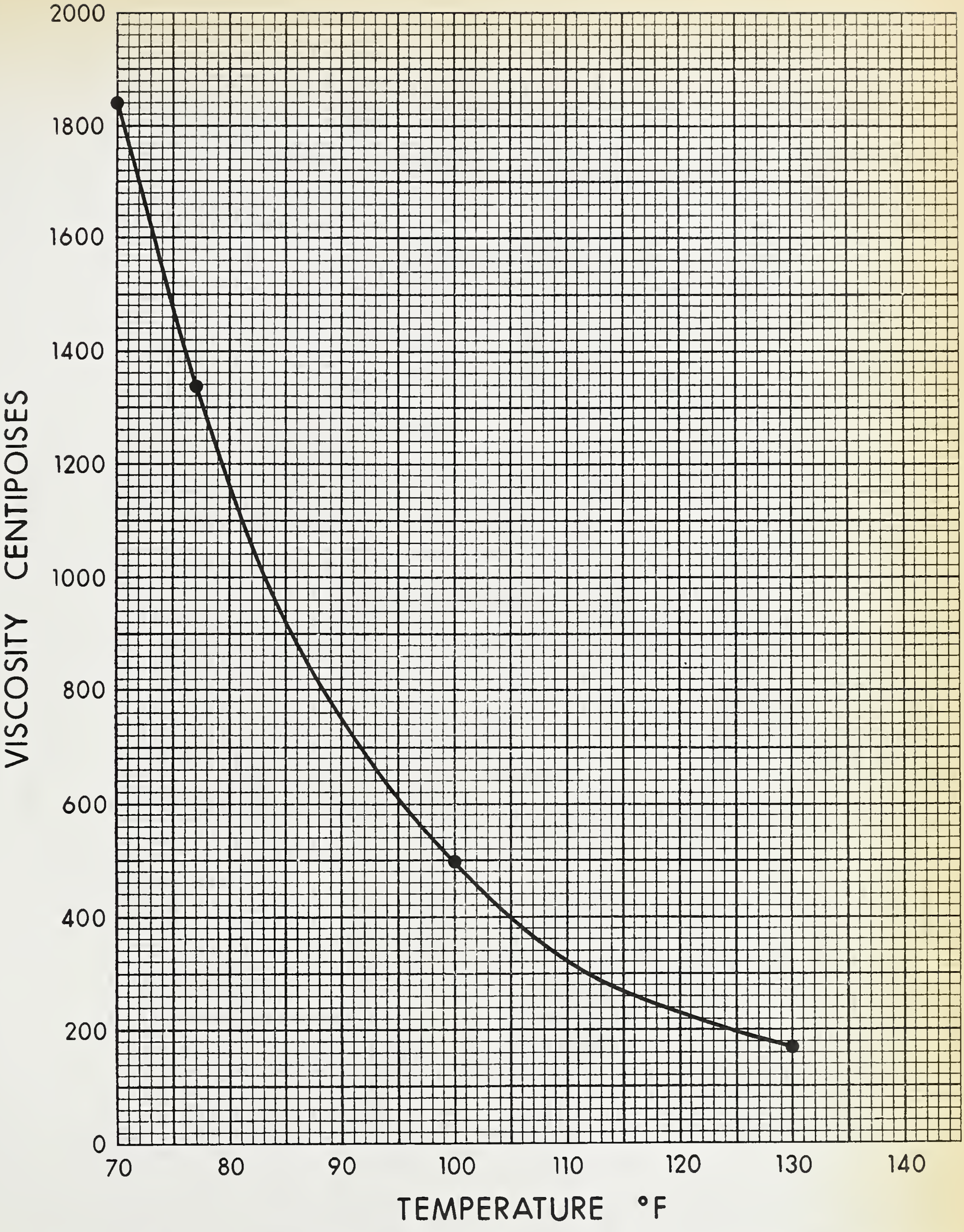

FIG. I-2 VISCOSITY OF DEAD LLOYDMINSTER CRUDE AS A FUNCTION OF TEMPERATURE

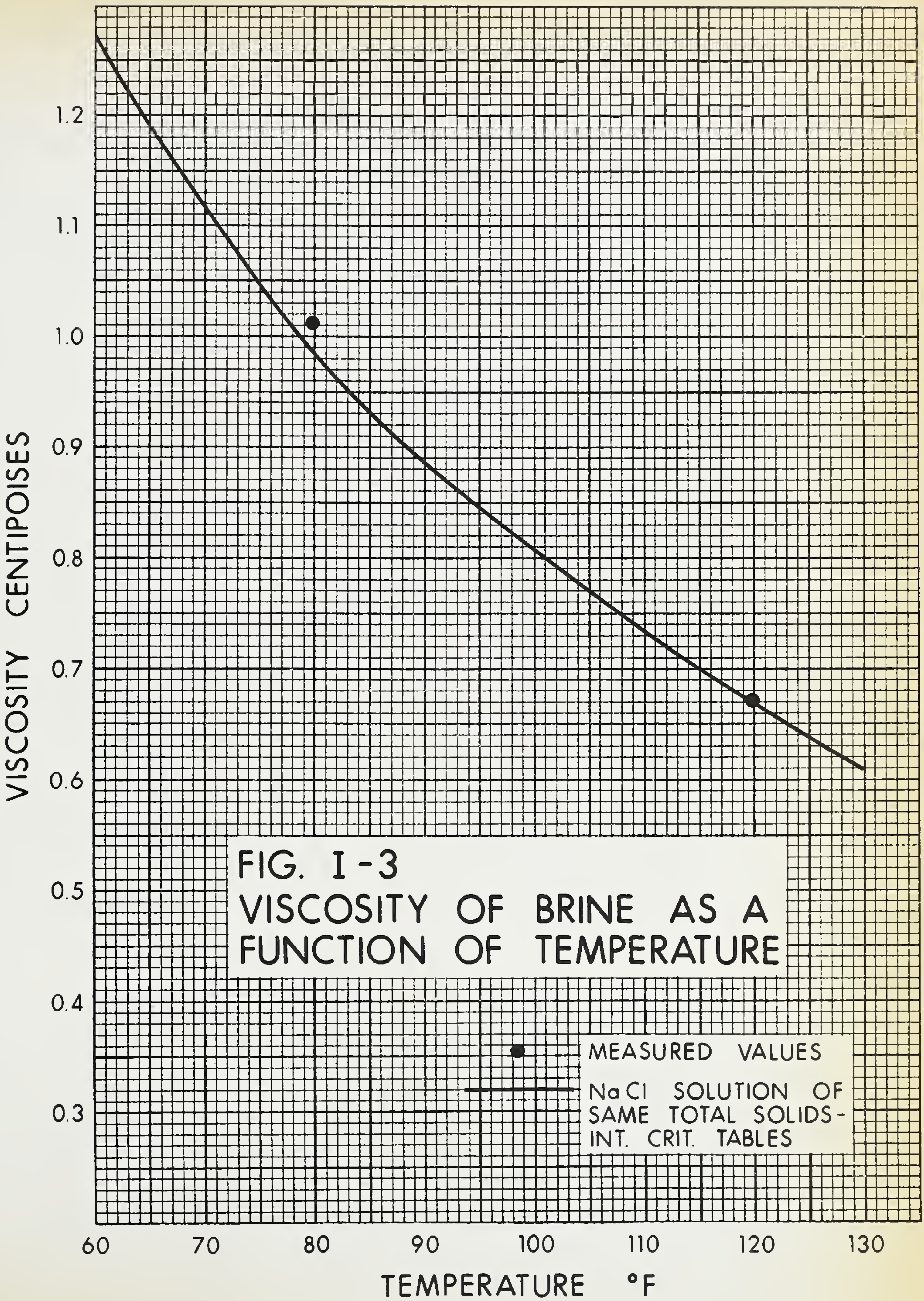

FIG. I-3
VISCOSITY OF BRINE AS A FUNCTION OF TEMPERATURE

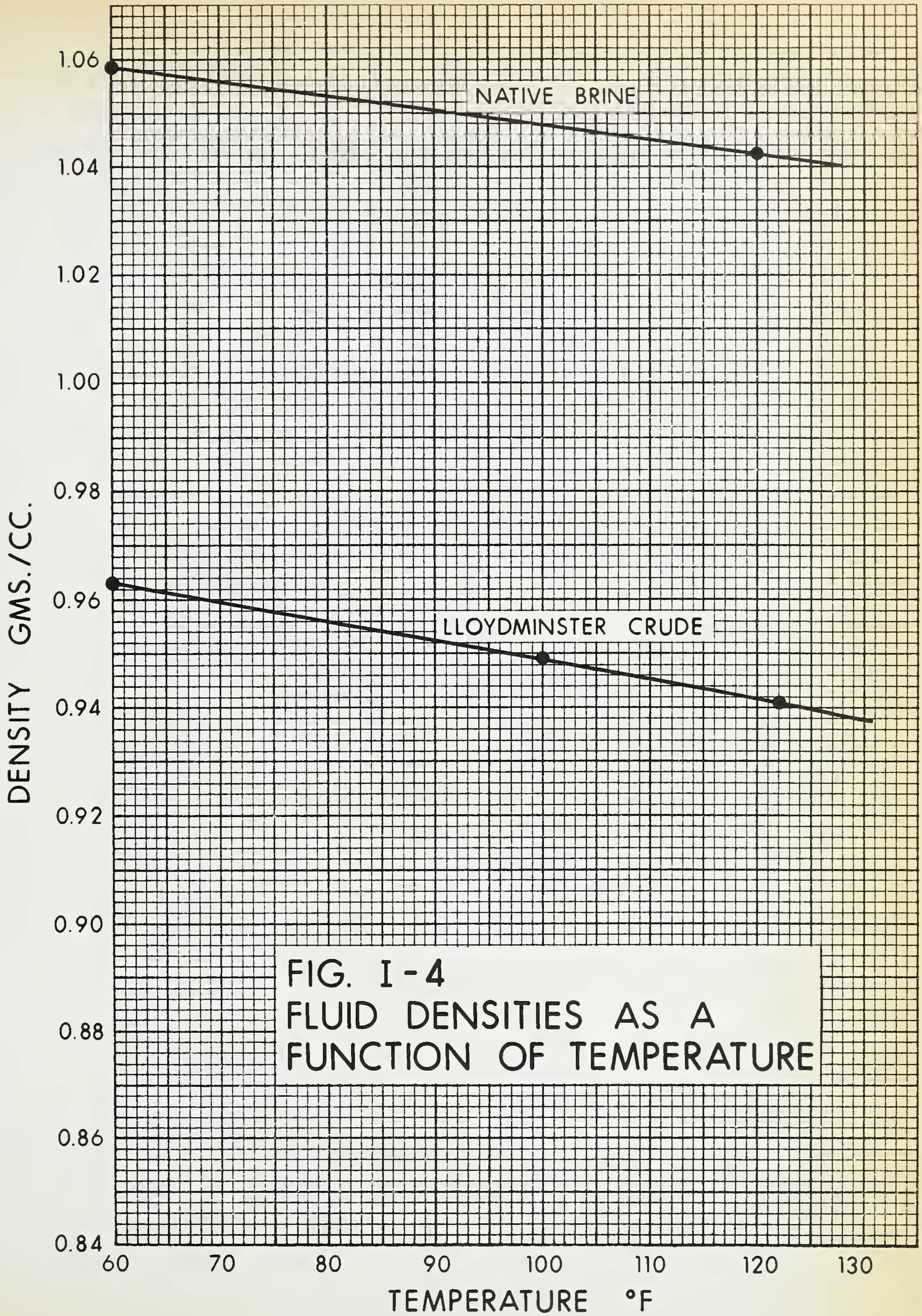

FIG. I-4
FLUID DENSITIES AS A FUNCTION OF TEMPERATURE

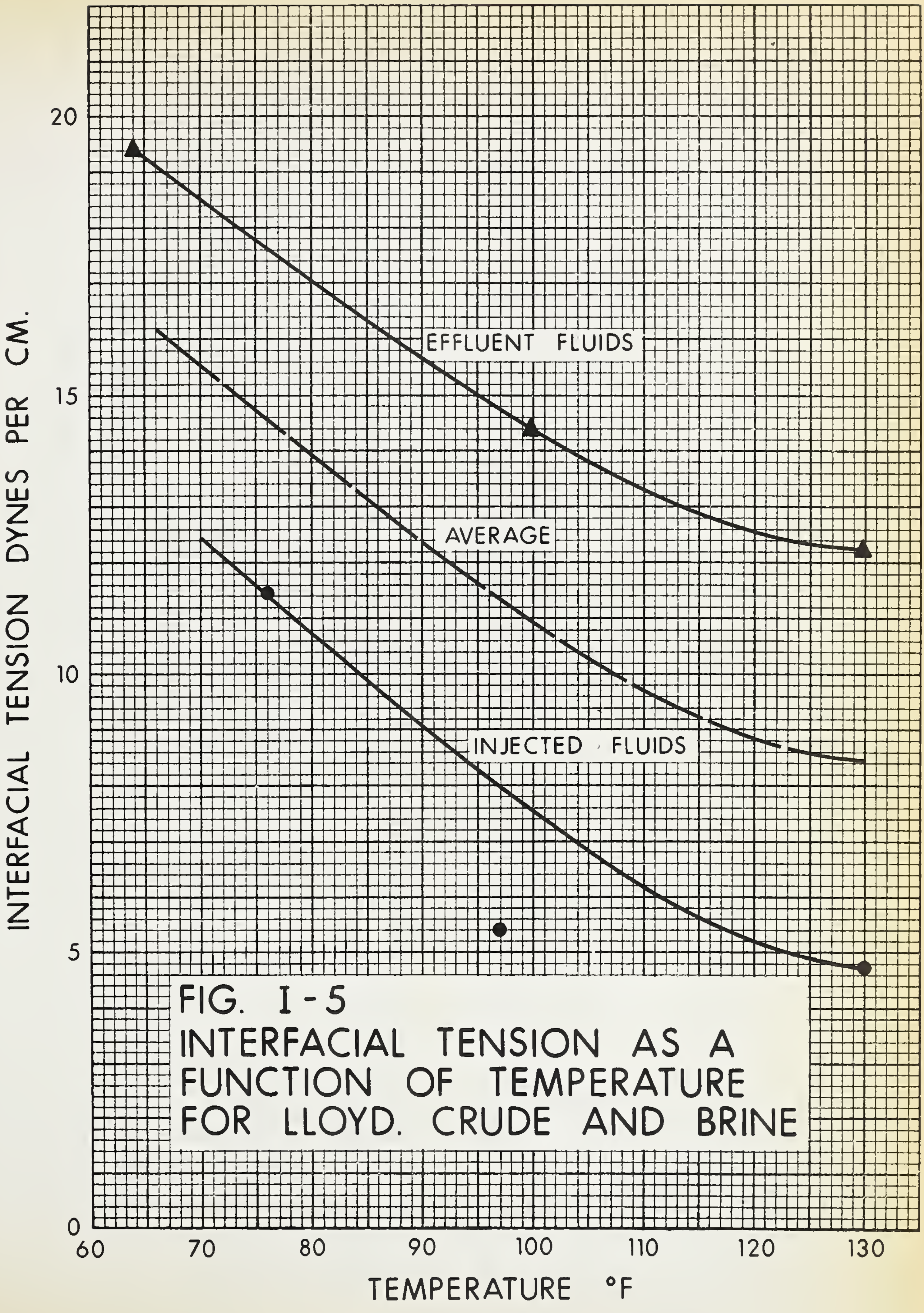

FIG. I - 5
INTERFACIAL TENSION AS A FUNCTION OF TEMPERATURE FOR LLOYD. CRUDE AND BRINE

APPENDIX II

TABLE II-1

STEADY STATE RELATIVE PERMEABILITY PRESSURE PROFILES

Rates in cc/hr

Temperature 100°F

Pressure, psig

Time Day-Hour	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End
				Ratio 5:1	25(W)*:	5(Oil)			
5-1100	185.6								289.0
5-1700	185.7	211.8	223.2	232.1	247.1	260.1	268.5	279.2	283.5
6-1000	185.1	212.0	227.4	238.5	252.1	260.8	271.0	280.8	286.0
6-1630	185.0	211.2	223.8	235.2	255.0	262.8	271.2	286.5	293.2
				Ratio 3:1	25(W):	8.33(Oil)			
7-1000	190.5	225.5	248.4	266.8	297.4	309.5	321.5	336.8	345.4
7-1630	187.5	225.2	248.2	272.5	295.8	309.0	321.2	336.6	345.8
				Ratio 1:1	15(W):	15(Oil)			
8-0930	196.5	253.5	293.2	335.0	378.7	396.2	417.0	444.5	463.5
8-1700	195.2	256.0	294.5	323.0	362.5	387.8	411.2	442.8	465.9
				Ratio 1:3	8.33(W):	25(Oil)			
9-1030	195.0	300	348	392	457	494	531	572	598
9-1700	195.0	293	357	400	470	510	553	597	623
10-1030	195.0	288	346	397	456	487	521	558	581

* W Water

TABLE II-2

STEADY STATE RELATIVE PERMEABILITY PRESSURE PROFILES

Rates in cc/hr — Temperature 100°F

Time Day-Hour	Down-Stream End	Pressure, psig — Tap Number 1	2	3	4	5	6	7	Upstream End
				Ratio 5:1	25(W):	5(Oil)			
11-1200	181.5	193.5	202.2	208.2	220.9	224.5	228.8	235.5	242.2
11-1730	185.5								278.0
12-1400	184.2	204.4	219.2	228.5	244.5	255.5	265.5	276.5	284.3
13-1200	184.5	208.1	222.5	233.2	243.6	250.5	259.0	268.5	275.0
				Ratio 15:1	30(W):	2(Oil)			
14-0900	181.5	194.0	201.1	205.0	209.2	212.8	216.0	219.2	221.2
14.1600	181.0	191.0	197.2	201.2	206.8	209.9	212.7	217.6	219.0
16-1000	180.6	191.2	199.3	202.8	211.8	215.1	217.2	222.4	224.3
17-1000	180.2	190.2	197.2	201.8	213.2	216.7	220.3	226.0	229.2
17-1800	181.0	191.5	197.5	203.8	209.1	212.2	216.8	220.5	223.2
				Reduced Rate	10(W):	0.667(Oil)			
20-1000	179.0								195.0

TABLE II-3

SUMMARY OF SATURATION DATA FOR STEADY STATE RELATIVE PERMEABILITY

Original Water Saturation 0.570

Oil Injected cum. cc.	Oil Recovered cum. cc.	Net Change cc.	Net Change p.v.	Stabilized S_w
		Ratio 5:1	25(W): 5(Oil)	
454	182	272	0.282	0.288
		Ratio 3:1	25(W): 8.33(Oil)	
627	334	293	0.304	0.266
		Ratio 1:1	15(W): 15(Oil)	
989	651	338	0.351	0.219
		Ratio 1:3	8:33(W): 25(Oil)	
1959	1609	350	0.364	0.206
		Ratio 5:1	25(W): 8.33(Oil)	
2262	1996	266	0.276	0.294
		Ratio 15:1		
2440	2212	228	0.237	0.333

TABLE II-4

STEADY STATE RELATIVE PERMEABILITY STUDY

Sample Calculation

WOR 5:1; 25:5 cc/hr

$$K = \frac{q\,u\,\Delta L}{A\,\Delta P}$$

$$= \frac{8 \times 30.5 \times 14.7}{11.43 \times 3600} \left(\frac{q\,u}{\Delta P}\right)$$

$$= 0.087 \left(\frac{q\,u}{\Delta P}\right)$$

where q is in cm^3/hr

u is in cps

Δ P is in psig

K is in darcies

Bath Temperature - 100°F — μ_w - 0.810

Mean Pressure - 139.1 — μ_o - 520 cps

ΔP - 108.2 — $K_{abs.}$ - 3.62 darcies

Stabilized S_w - 0.288

$$K_o = \frac{8.7 \times 10^{-2} \times 5 \times 520}{108.2} = 2.09 \text{ darcies}$$

$$k_o = \frac{2.09}{3.62} = 0.578$$

$$K_w = \frac{8.7 \times 10^{-2} \times 25 \times 0.81}{108.2} = 0.0163 \text{ darcies}$$

$$k_w = \frac{0.0163}{3.62} = 0.0045$$

$$\frac{k_w}{k_o} = 7.79 \times 10^{-3}$$

APPENDIX III

TABLE III-1

DISPLACEMENT TEST PRESSURE DATA - Test Number 9

S_{wc} - 0.136 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 667 Rate - 50 cc/hr

Time	Down-Stream End	1	2	3	4	5	6	7	Upstream End
	Pressure, psig — Tap Number								
(Hr.-Day)	AT CONNATE WATER SATURATION								
1130-4	168	213	275	340	407	530	620	695	772
1230-5	168	208	278	336	407	530	620	698	775
1130-7	168	208	282	343	407	532	621		770
(Mins.)	DURING DISPLACEMENT								
30-47	168	208	270	336	403	525	593**	620	630
							(45)		
50-64	172	212	272	335	398	502	550	573	578
						(61)			
70-105	170	208	271	336	402-(78)	455	487	503	508
					392-(101)				
108-114	172	212	272	336	383	443	471	485	488
127-138	170	208	271	334	369	418	441	455	458
* 150-180	166	206	266	300	318	352	370	384	387
			(171)	(173)					
182-195	166	207	249	276	294	326	340	341	348
			(189)						
206-224	166	207	225	240	252	278	291	300	302
B.T. 220									
270	154	171		204		240		262	264
360-390	154	165	175	190	198	216	225	230	232
1320	152	155	160	165	169	175	181	182	183
2640	151	153.5	157	160	162	167	169	172	173

* Switched to 0-500 psig gauge. ** Numbers in brackets are time in minutes.

TABLE III-2

DISPLACEMENT TEST PRESSURE DATA - Test Number 10

S_{w_c} - 0.14 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 669 Rate - 50 cc/hr

Time	Down-Stream End	Pressure, psig Tap Number 1	2	3	4	5	6	7	Upstream End
(Hr.-Day)		A T C O N N A T E W A T E R S A T U R A T I O N after resaturating w. 400 cc's crude							
2100-10	167	206	266	333	403	531	622	700	785
		flowed additional 450 cc's crude							
0930-11	168	212	278	345	415	541	632	718	800
(Mins.)		D U R I N G D I S P L A C E M E N T							
20-30	168	212	285	356	427	550	638 (29)	680	690
37-47	170	212	278	348	416	543	612 (45)	642	659
51-60	168	212	287	356	427	546	598 (59)	622	628
70-81	168	212	277	348	418	517 (79)	557	577	582
115-125	168	210	273	345	392	450	474	487	492
* 168-189	166	216	264 (182)	292	310	338	354	364	367
B.T. <u>198</u>	161								
200-222	165	201	222	245	259	284	298	308	311
231	160								

TABLE III-2 (Continued)

Pressure, psig

Time	Down-Stream End	1	2	3	Tap Number 4	5	6	7	Upstream End
240-260	160	177	193	213	226	248	263	271	273.5
	154								
618-635	152	158	166	176	183	198	204	206.5	208.5
1260-1280	152	156	161	166½	171½	179	183	185.5	187
1680	153								181
2760	152	154	156.5	160	162	167	171	173.5	174

* Switched to 0-500 psi gauge.

TABLE III-3

DISPLACEMENT TEST PRESSURE DATA - Test Number 11

S_{w_c} - 0.130 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 648 Rate - 10 cc/hr

Time	Down-Stream End	1	2	3	4	5	6	7	Upstream End
		Pressure, psig — Tap Number							
(Hr.-Day)		AT CONNATE WATER SATURATION after resaturating w. 875 cc's crude (50 cc/hr)							
2000-14	168	205	262	340	418	540	634	700	780
		at 10 cc's/hr							
1330-15	155	164	178	193	209	232	248	262	277
(Mins.)		DURING DISPLACEMENT							
86-98	155	163	176	189	201	232	246	255 (97)	257
180-220	155	164	175	187	199	222 (215)	236	244	246
576-605	155	165	175	188	199	211 (600)	218	220	221
1080-1122	155	164	168½ (1100)	175	181	182	183.5	185	186
1230-1240	155	162 (1230)	165	168½	177	181	182.5	184	185
1245-	155	161	164	167½	176	178	179	180½	181
B.T. 1295-1320	154	157	159½	163	165½	170½	172½	173½	174½
1500-1527	152	155	157	160	163	167	168½	169½	170½
1890-1920	151	154	157	159	162	165	167	168½	168½
2700-	152	153	154	155½	157	160	160½	162	162½

TABLE III-4

DISPLACEMENT TEST PRESSURE DATA - Test Number 12

S_{w_c} - 0.138 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 646 Rate 2.5 cc/hr

Pressure, psig

	Time	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End
	(Hr.-Day)	AT CONNATE WATER SATURATION Rate - 50 cc's/hr								
		168	212	278	348	420	563	657	745	835
		DURING DISPLACEMENT								
	1200-18	150								183(calc.)
	1300-18	150								177
	1630-18	153	155	158	161	163	167	170	172	175
	1000-19	153	154	156	158	161	166	169	171	171½
	1700-19	153			161	163	169	173	174	175
	1200-20	153	155	158	162	163	165	166	167	170
										167
	0900-21	153	155	158	162	163	164	165	165	170
										166
	1600-21	154	156	158	158	159	160	161	161	162
	0000-22	153	157	159	159	159	160	161	161	162
	0900-22	152	153	154	155	155½	158	160	161	161
B.T.	1130-22	152								157
	1630-22	151½								155
	0030-23	151½								154½
	1200-23	150.7								153

TABLE III-5

DISPLACEMENT TEST PRESSURE DATA - Test Number 13

S_{w_c} - 0.138 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 680 Rate - 80 cc/hr

Time	Down-Stream End	Pressure, psig: Tap Number 1	2	3	4	5	6	7	Upstream End
(Hr.-Day)	AT CONNATE WATER SATURATION Rate - 50 cc/hr								
1100-24	163	211	282	353	418	562	655	735	827
	DURING DISPLACEMENT								
27-34	170	241	350	467	580	795	890	947	965
							(33)		
34-45	175	246	353	475	595	798	868	902	912
							(44)		
60-70	175	248	354	473	555	673	716	740	748
					(67)				
82-93	175	248	347	421	471	555	588	608	612
			(89)						
102-112	175	246	310	363	402	465	490	507	511
		(105)							
B.T. <u>123</u>-133	169	208	253	293	317	365	390	406	410
		(128)							
177-182	162	183	208	235	252	295	314	328	331
348-360	153	163	177	192	206	229	240	248	253
660	151	158½	167	177	185	199	208	211	215
1200	151	155½	160	167	173	185	188½	192	195
1440	151								190

TABLE III-6

DISPLACEMENT TEST PRESSURE DATA - Test Number 14

S_{w_c} - 0.131   Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 663   Rate - 30 cc/hr

Pressure, psig

	Time	Down-Stream End	1	2	3	Tap Number 4	5	6	7	Upstream End
	(Hr.-Day)	A T C O N N A T E W A T E R S A T U R A T I O N Rate 40 cc/hr								
	0900-28	165	196	249	297	347	435	500	590	721
	(Mins.)	D U R I N G D I S P L A C E M E N T								
	0	163	187	228	271	309	373	419	486	590
	44-51	163	189	228	263	300	361	406	456	476
*	63-88	166	189	233	262	302	373	412 (86)	439	450
	102-128	165	194	235	265	297 (120)	354 (123)	381	396	405
	148-160	166	194	231	263	298 (156)	350	365	375	382
	195-215	166	190	228	262	290 (209)	318	333	343	349
	273-285	166	189	223 (275)	244 (276)	262	280	287	293	296
	294-307	165	189	218 (300)	234	244	259	266	272	276
	316-330	165	187 (319)	211	229	238	250	256	262	265.5
B.T.	380	164	177	191	201	209	220	225	231	234
	470	158								218
	560	155								203
	740	156								192

* Changed to 0-500 psi gauge.

TABLE III-7

DISPLACEMENT TEST PRESSURE DATA - Test Number 15

S_{w_c} - 0.141 Temperature - 77°F $(\mu_o/\mu_w)_{ave.}$ - 430 Rate - 30 cc/hr

Pressure, psig

Time	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End
(Hr.-Day)	AT CONNATE WATER SATURATION (Temperature - 100°F)								
1330-30	163	189	235	275	313	378	425	493	603
(Mins.)	DURING DISPLACEMENT								
0	165	228	340	445	553	743	878	1028	1365
33-50	165	225	330	435	535	735	867	992	1045
								(48)	
65-81	167	227	328	425	546	730	830	900	930
							(78)		
120-133	165	233	348	450	544	663	712	747	765
						(130)			
150-160	165	231	338	432	500	585	622	652	668
					(156)				
180-195	168	230	327	393	446	513	541	563	575
				(185)					
218-226	168	218	286	335	375	433	457	500	512
		(220)							
B.T. 243	165	206	265	308	342	388	410	427	438
420	159								305
940	153								210

TABLE III-8

DISPLACEMENT TEST PRESSURE DATA - Test Number 16

S_{w_c} - 0.144 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 292 Rate 30 cc/hr

Time	Down-Stream End	1	2	3	4	5	6	7	Upstream End
	Pressure, psig								
					Tap Number				
(Hr.-Day)	AT CONNATE WATER SATURATION Temperature 100°F								
2230-1	167	186	227	266	311	378	423	489	600
(Mins.)	DURING DISPLACEMENT								
0	162	170	186	202	215	238	256	280	319
41-54	166.5	175	190	203	217	239	255	276 (53)	284
70-82	164.5	173	188	202	216	238	255	269 (81)	274
101-116	165	173.5	188	201	216	239	255	262 (115)	266
150-163	165	173.5	188	202	216	239	247 (160)	251	253
205-215	165.5	174.5	191	205	218	231 (213)	235	237	237
247-260	165	172	187	200.5	211 (255)	219	222	225	227
292-302	165	173.5	188	200.5 (298)	206	212	215	217.5	219.5
337-345	166	174	188	195.5 (343)	199.5	204	206.5	209	210.5

TABLE III-8 (Continued)

Pressure, psig

	Time	Down-Stream End	1	2	3	4	5	6	7	Upstream End
			Tap Number							
	397-405	164	172	180.5 (400)	185	187.5	191.5	194	196	198
	444-451	163	169 (447)	173.5	177	179.5	183	185	187	188.5
B.T.	462-468	160	163	167	170	173	176.5	178.5	179.5	181
	625	156								170
	740	153.5								168.5

TABLE III-9

DISPLACEMENT TEST PRESSURE DATA - Test Number 17

S_{w_c} - 0.154 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 307 Rate - 200 cc/hr

Time	Down-Stream End	1	2	3	4	5	6	7	Upstream End
					Pressure, psig				
					Tap Number				
(Hr.-Day)	AT CONNATE WATER SATURATION Rate 30 cc/hr								
	165	174	188.5	201	215.5	239	256.5	280	325
	DURING DISPLACEMENT								
(Mins.)	196	250	346	438	536	702	817	980	1270
0	199								1050(max.)
5-10	199				540	707	826	944(9)	965
12-15				443	539	706	797 (14)	858	890
16-19					535	697 (18)	765	810	835
20-22				440	538	675 (21)	725	763	785
23-24				440	532 (23)	655	700	735	755
24-26				440 (24)	528 (25)	602	668	698	716
27-29				440	514 (28)	598	633	660	678
31-33				433 (31)	494	565	596	618	635

TABLE III-9 (Continued)

Pressure, psig

	Time	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End
	34-36	190	248	342	413	463	525	550	570	586
					(35)					
	37-39				398	440	495	517	538	552
					(37½)					
	40-43	190	242	320	373	411	462	482	502	514
				(41)						
	46-48	191	235	293	328	365	406	425	443	454
			(46)							
B.T.	51-54	179	214	265	298	326	363	380	395	406
	78	163								310
	108	158								268
	138	157								240

TABLE III-10

DISPLACEMENT TEST PRESSURE DATA - Test Number 18

S_{w_c} - 0.144 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 292 Rate - 10 cc/hr

Time	Down-Stream End	1	2	3	4	5	6	7	Upstream End
	Pressure, psig				Tap Number				
(Hr.-Day)	AT CONNATE WATER SATURATION								
	Rate - 30 cc/hr								
	profile after 500 cc's crude injected for resaturation								
1230-4	165	174	188½	201½	214½	238	256.5	276	320
	after additional 350 cc's crude injected								
1030-5	165	173	186½	199½	213½	236	253	275	323
(Mins.)	DURING DISPLACEMENT								
0	156	159	163	170	174	180	185	191	207
60-73	156	158.5	163	169	172.5	179.5	184	190.5	199
120-136	156	158.5	163	170.5	175	181	185.5	191	194.5
								(135)	
198-206	157						188	192.5	194
								(205)	
267-275	156	159					184	189	192
							(273)		
352-360	157					181	185.5	186	187
							(359)		

TABLE III-10 (Continued)

Pressure, psig

	Time	Down-Stream End	1	2	3	Tap Number 4	5	6	7	Upstream End
	634-655	157	160.5	163	170	173 (648)	176.5	181	181.5	181.5
	1240-1250	156.5	159.5	161.5 (1250)	163	164	165.5	166	166.3	167.0
	1353-1360	156.5	160.5	162 (1357)	162.5	163	163.5	164.5	165	166.5
	1385-1390	157	158.5 (1390)	160	161.5	162.5	163	163.8	164	164.5
B.T.	1472	155	155.5	156	156.5	157.5	159.5	159.5	160.2	160.5
	1810	151.5								156.2
	2280	151.5								156.5

TABLE III-11

DISPLACEMENT TEST PRESSURE DATA - Test Number 19

S_{w_c} - 0.141   Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 292   Rate - 2.5 cc/hr

Pressure, psig

Time	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End	
(Hr.-Day)	AT CONNATE WATER SATURATION									
	Rate - 30 cc/hr									
	profile after 500 cc's crude injected for resaturation									
30 cc/hr	163.5	172	186	200	213½	236	253	275	322	
	profile after additional 500 cc's injected									
30 cc/hr	163	172	186	200	214	235	251	275	321	
(Mins.)	DURING DISPLACEMENT									
0	152½	153.3	154.5	155.7	156.9	158.7	160	162	166	
570	153								160.5	
1500	154						160	160.7	161.2	
1500	154½	155.3	156.3	157.5	157(?)	160.1	160	159.2!	159.5	very unstable
2640	154	154.2	158!	157	157.8	158.3	158.3	158.9	159.5	
2645	154	154.2	155	156.1	157.1	158.2	158.8	159.0	159.3	
3060	154								158.8	
4380	154								157.8	
5520	154½								156	
B.T. 6000	153.8								155.2	
7000	152.3								153.2	
8320	151.3								152.2	
9050	152.2								153.3	

TABLE III-12

DISPLACEMENT TEST PRESSURE DATA - Test Number 20

S_{w_c} - 0.141   Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 296   Rate - 80 cc/hr

Pressure, psig

Time	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End
(Hr.-Day)	AT CONNATE WATER SATURATION Rate - 30 cc/hr								
1030-16	164	172½	187	201	215	238	254	275	325
(Mins.)	DURING DISPLACEMENT								
0-1150-16	172	195	236	273	311	372	417	477	602
9-12	175						412	475	513
							(10)	(11)	(12)
18-21	175					370	413	462	483
							(19)	(20)	(21)
* 30-34	174					372	413	444	453
							(32)	(33)	(34)
44-47						373	402	418	429
						(45)	(46)		
57-63					312	368	384	395	404
						(61)	(61)		
75-81				276	308	337	347	356	362
					(78)	(79)			
90-96				274	297	318	327	333	339
				(91)	(92)	(93)	(94)		
106-112			237	266	281	296	303	310	316
				(109)					
120-132			232	247	256	269	275	281	286
			(123)	(127)					
139-145	175	198	220	232	241	252	257.5	263.5	268.5
			(141)	(142)					

TABLE III-12 (Continued)

Pressure, psig

	Time	Down-Stream End	Tap Number 1	2	3	4	5	6	7	Upstream End
	150-155	174	193 (151)	210	221	229	241	246.5	252	256.5
B.T.	162-168	169	179	192	200	207	217	222.5	227	232
	192	156								210
	244	158								203
	285	157								197

* Switched to 0-500 gauge.

TABLE III-13

DISPLACEMENT TEST PRESSURE DATA - Test Number 21

S_{w_c} - 0.144 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 296 Rate - 80 cc/hr

Pressure, psig

Time (Mins.)	Down-Stream End	1	2	3	Tap Number 4	5	6	7	Upstream End
	AT CONNATE WATER SATURATION Rate - 30 cc/hr								
	164	173	188	201½	216	239	255	276	331
	reversed core								
	165	198	218	233	256	271	284	299	308
	DURING DISPLACEMENT								
0	174	263	318	363	427	467	504	547	573
12-14	175						490 (13)	533 (14)	547
18-22						452 (20)	490 (20)	530 (21)	539
26-32	175	258	315	358	423	463	500	526 (31)	530
45-47						463	487 (46)	503	506
57-60					423	451 (58)	469	479	481
76-86				358	399 (82)	415	426	431	432
92-106	174	258	315	346 (99)	379	385	389	392	392½

TABLE III-13 (Continued)

			Pressure, psig							
		Down-Stream	Tap Number							Upstream
	Time	End	1	2	3	4	5	6	7	End
	116-123	175	246	281	303	329	338	344	348	349½
			(119)	(120)						
B.T.	135-142	172	229	261	282	301	308	313	317	318
	174	168								285
	267	160								220
	300	158								212
	360	157								204
	1140	155								181
	1500	155								175
	1875	155								171
	3360	154								160½
	4080	154								160.3
	4740	153.5								159.2

TABLE III-14

DISPLACEMENT TEST RECOVERY DATA - Test Number 9

S_{w_c} - 0.136 Temperature - 100^{o}F $(\mu_o/\mu_w)_{ave.}$ - 667 Rate - 50 cc/hr

Pore Volume - 1003 cc

Time	Pump Reading	Injected* Q_i Cum. cc.	Injected* Q_i Cum. p.v.	Recovered Water Inst. cc	Recovered Water Cum. cc	Recovered Oil Inst. cc	Recovered Oil Cum. cc	Recovered Oil Cum. p.v.
0	0							
120	100	98		tr	tr	98	98	
220	183	181	0.180	tr	tr	83	181 B.T.	0.180
270	235	232	0.231	28	28	19	204	0.203
		357	0.356	100	128	25	229	0.228
		554	0.553	173	301	24	253	0.252
		1060	1.057	470	771	36	289	0.288
		1710	1.705	620	1391	30	319	0.318
		2315	2.308	585	1976	20	339	0.338

* Figures modified to make injected recovered.

TABLE III-15

DISPLACEMENT TEST RECOVERY DATA - Test Number 10

S_{w_c} - 0.140 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 669 Rate - 50 cc/hr

Pore Volume - 1003 cc

		Injected		Recovered				
				Water			Oil	
Time	Pump Reading	Q_i Cum. cc.	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
		99		3		96		
		163		2	5	62	159	
231	192	195		2	7	30	188 B.T.	
		261		44	51	22	210	
		505		210	261	34	244	
		1011		464	725	42	286	
		1421		393	1118	17	303	
		1931		495	1613	15	318	
		2366		423	2036	12	330	

TABLE III-16

DISPLACEMENT TEST RECOVERY DATA - Test Number 11

S_{w_c} - 0.130 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 648 Rate - 10 cc/hr

Pore Volume - 1003 cc

		Injected		Recovered				
				Water		Oil		
Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
	216	96		2		94		
		193		2	4	95	189	0.188
1295		210	0.209	1	5	16	207 B.T.	0.206
		254	0.253	28	33	16	233	0.232
		313	0.312	48	81	11	244	0.243
		426	0.424	96	177	17	261	0.260
		486	0.484	53	230	7	268	0.267

TABLE III-17

DISPLACEMENT TEST RECOVERY DATA - Test Number 12

S_{w_c} - 0.138 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 292 Rate - 2.5 cc/hr

Pore Volume - 1003 cc

		Injected		Recovered				
				Water		Oil		
Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
0	200							
$94\frac{1}{2}$	436	216*	0.215	3		213	213 B.T.	0.212
	471	249	0.248	24	27	9	222	0.221
		277	0.276	22	49	6	228	0.227

* Figure adjusted for discrepancy between injected and recovered quantities.

TABLE III-18

DISPLACEMENT TEST RECOVERY DATA - Test Number 13

S_{w_c} - 0.138 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 680 Rate - 80 cc/hr

Pore Volume - 1003 cc

		Injected		Recovered				
				Water		Oil		
Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
		100		3	3	97		
	160	160	0.159	3	6	57	154 B.T.	0.153
		239	0.238	44	50	35	189	0.188
		339	0.337	79	129	21	210	0.209
		393	0.391	46	175	8	218	0.217
		493	0.490	88	263	12	230	0.229
		898	0.895	375	638	30	260	0.259
		1908	1.902	970	1608	40	300	0.299

TABLE III-19

DISPLACEMENT TEST RECOVERY DATA - Test Number 14

S_{w_c} - 0.131 Temperature - 100°F $(\mu_o/\mu_w)_{ave.}$ - 663 Rate - 30 cc/hr

Pore Volume - 963 cc

		Injected			Recovered				
				Water		Oil			
	Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
	210	100	100		2	2	98	98	
B.T.	380	191	191	0.196	1	3	90	188 B.T.	0.195
	470	236	236	0.242	25	28	20	208	0.216
	560	282	283	0.291	34	62	13	221	0.230
	740	372	373	0.383	73	135	17	238	0.247

TABLE III-20

DISPLACEMENT TEST RECOVERY DATA - Test Number 15

S_{w_c} - 0.131 Temperature - 77°F $(\mu_o/\mu_w)_{ave.}$ - 1430 Rate - 30 cc/hr

Pore Volume - 463 cc

		Injected		Recovered				
				Water		Oil		
Time	Pump Reading	Q_1 Cum. cc	Q_1 Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
0	- 02							
200	98	100	0.104	3	3	97		
243	120	122	0.126	1	4	27	118 B.T.	0.122
420	213	216	0.224	50	54	44	162	0.168
940	467	470	0.488	210	264	44	206	0.214

TABLE III-21

DISPLACEMENT TEST RECOVERY DATA - Test Number 16

S_{w_c} - 0.144 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 292 Rate - 30 cc/hr

Pore Volume - 963 cc

	Injected			Recovered				
				Water		Oil		
Time (Mins.)	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
200	100	100		2		98		
	200	200		2	4	98	196	0.203
462	232	233	0.242	tr	4	33	229 B.T.	0.238
625	310	314	0.326	59	63	22	251	0.260
740	370	374	0.388	51	114	9	260	0.270

TABLE III-22

DISPLACEMENT TEST RECOVERY DATA - Test Number 17

S_{w_c} - 0.154 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 307 Rate - 200 cc/hr

Pore Volume - 963 cc

		Injected		Recovered				
				Water		Oil		
Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
30	100	100		2		98		
51	170	170	0.1765	4	6	66	164 B.T.	0.170
78		269	0.279	54	60	45	209	0.217
108		368	0.382	76	136	23	232	0.241
138		467	0.486	85	221	14	246	0.256

TABLE III-23

DISPLACEMENT TEST RECOVERY DATA - Test Number 18

S_{w_c} - 0.144 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 292 Rate - 10 cc/hr

Pore Volume - 963 cc

		Injected		Recovered				
				Water		Oil		
Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
(Mins.)								
660	110	110				110		
1320	210	210		2	2	98	208	
1474	245	246	0.255	2	4	34	242 B.T.	0.251
1810	302	302	0.314	41	45	15	257	0.267
2280	380	380	0.394	68	113	10	267	0.277

TABLE III-24

DISPLACEMENT TEST RECOVERY DATA - Test Number 19

S_{w_c} - 0.141 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 293 Rate - 2.5 cc/hr

Pore Volume - 963 cc

Time	Pump Reading	Injected Q_i Cum. cc	Injected Q_i Cum. p.v.	Recovered Water Inst. cc	Recovered Water Cum. cc	Recovered Oil Inst. cc	Recovered Oil Cum. cc	Recovered Oil Cum. p.v.
(Mins.)								
	0							
2640	110	109		0		109		
5520	230	227		tr		118	227	
6000	249	247	0.256	1	1	19	246 B.T.	0.255
7000	291	289	0.300	30	31	12	258	0.268
8320	348	347	0.360	46	78	12	270	0.280
9050	377	377	0.391	25	103	5	275	0.286

TABLE III-25

DISPLACEMENT TEST RECOVERY DATA - Test Number 20

S_{w_c} - 0.141 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 296 Rate - 80 cc/hr

Pore Volume - 963 cc

			Injected		Recovered				
					Water		Oil		
	Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
		100	99		1	1	98		
		199	199		1	2	99	197	
B.T.		216	219	0.227	1	3	19	216 B.T.	0.224
		256	258	0.268	22	25	17	233	0.242
		312	316	0.326	45	70	13	246	0.255
	285	380	386	0.401	59	129	11	257	0.267

TABLE III-26

DISPLACEMENT TEST RECOVERY DATA - Test Number 21

S_{w_c} - 0.144 Temperature - 130°F $(\mu_o/\mu_w)_{ave.}$ - 296 Rate - 80 cc/hr

Pore Volume - 963 cc

	Injected			Recovered				
				Water		Oil		
Time	Pump Reading	Q_i Cum. cc	Q_i Cum. p.v.	Inst. cc	Cum. cc	Inst. cc	Cum. cc	Cum. p.v.
0	100							
81	207	103	0.107			103		
135	280	179	0.186	3		73	176 B.T.	0.183
174	330	229	0.238	21	24	29	205	0.213
267	453	353	0.366	81	105	43	248	0.258
300	504	404	0.420	43	148	8	256	0.266
360	100	503	0.523	87	235	12	268	0.278
reduced rate to 40 cc/hr								
1140	504	1006	1.042	461		42	310	0.322
increased rate to 80 cc/hr								
1500	485	1489	1.55	460		23	333	0.346
1875	504	1992	2.07	490		13	346	0.359
reduced rate to 40 cc/hr								
3360		2912	3.03		895	25	371	0.385
4080		3412	3.54		488	12	383	0.398
4740		3849	4.0		426	11	394	0.409
6195		4824	5.0		958	17	411	0.426

TABLE III-27 SAMPLE CALCULATION

UNSTEADY STATE RELATIVE PERMEABILITY

Test No. 9

Welge Method(56)

S_w ave.	Q_i p.v.	f_o	$f_o\ Q_i$	S_{w2}	$\frac{1-f_o}{f_o}$	μ_o	μ_o/μ_w	K_w/K_o	
0.316	0.180	0.563	0.101	0.215	0.776	537	663	$1.17\times10^{-}$	Not usable account high saturation gradient
0.339	0.231	0.287	0.066	0.273	2.48	532	657	3.78×10^{-3}	
0.364	0.356	0.156	0.055	0.309	5.46	530	654	8.34×10^{-2}	
0.388	0.553	0.108	0.060	0.328	8.26	528	652	1.27×10^{-2}	
0.424	1.057	0.061	0.064	0.360	15.40	525	648	2.38×10^{-2}	
0.454	1.706	0.040	0.068	0.386	24.00	525	648	3.71×10^{-2}	
0.474	2.308	0.027	0.062	0.412	36.00	525	648	5.56×10^{-2}	

TABLE III-27 SAMPLE CALCULATION (Continued)

Johnson, Bossler, Naumann Extension(25)

$1/Q_1$	I_r	$1/I_r$	$\frac{1}{Q_1 I_r}$	$\frac{f_o}{K_{ro}} = \frac{d(\frac{1}{Q_1 I_r})}{d(\frac{1}{Q_1})}$	K_{ro}	K_{rw}	S_{w2}	
5.53	4.20	0.238	1.32	0.4	1.4	0.00164	0.215	Not usable account high saturation gradient
4.31	-5.30	0.189	0.813	0.36	0.80	0.00302	0.273	
2.81	8.0	0.125	0.351	0.244	0.64	0.00534	0.309	
1.81	11.7	0.0855	0.155	0.145	0.75	0.00952	0.326	
0.945	17.7	0.0565	0.0534	0.098	0.62	0.01475	0.360	
0.586	30.5	0.0327	0.0192	0.083	0.48	0.01780	0.386	
0.433	50.7	0.0197	0.0085	0.077	0.35	0.01945	0.412	

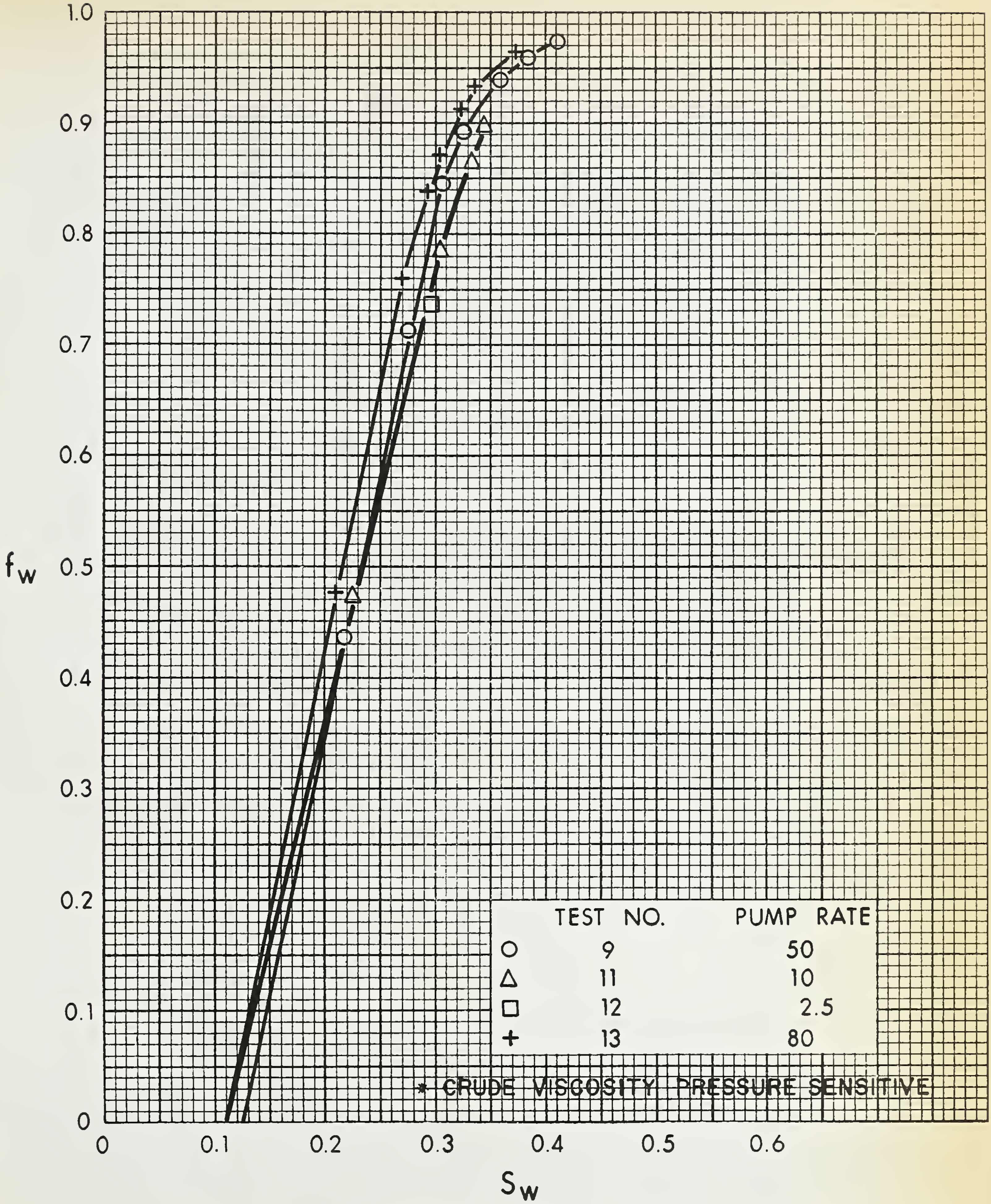

FIG. III - 1 FRACTIONAL FLOW CURVES FOR RATE STUDY AT μ_o^*/μ_w = 646

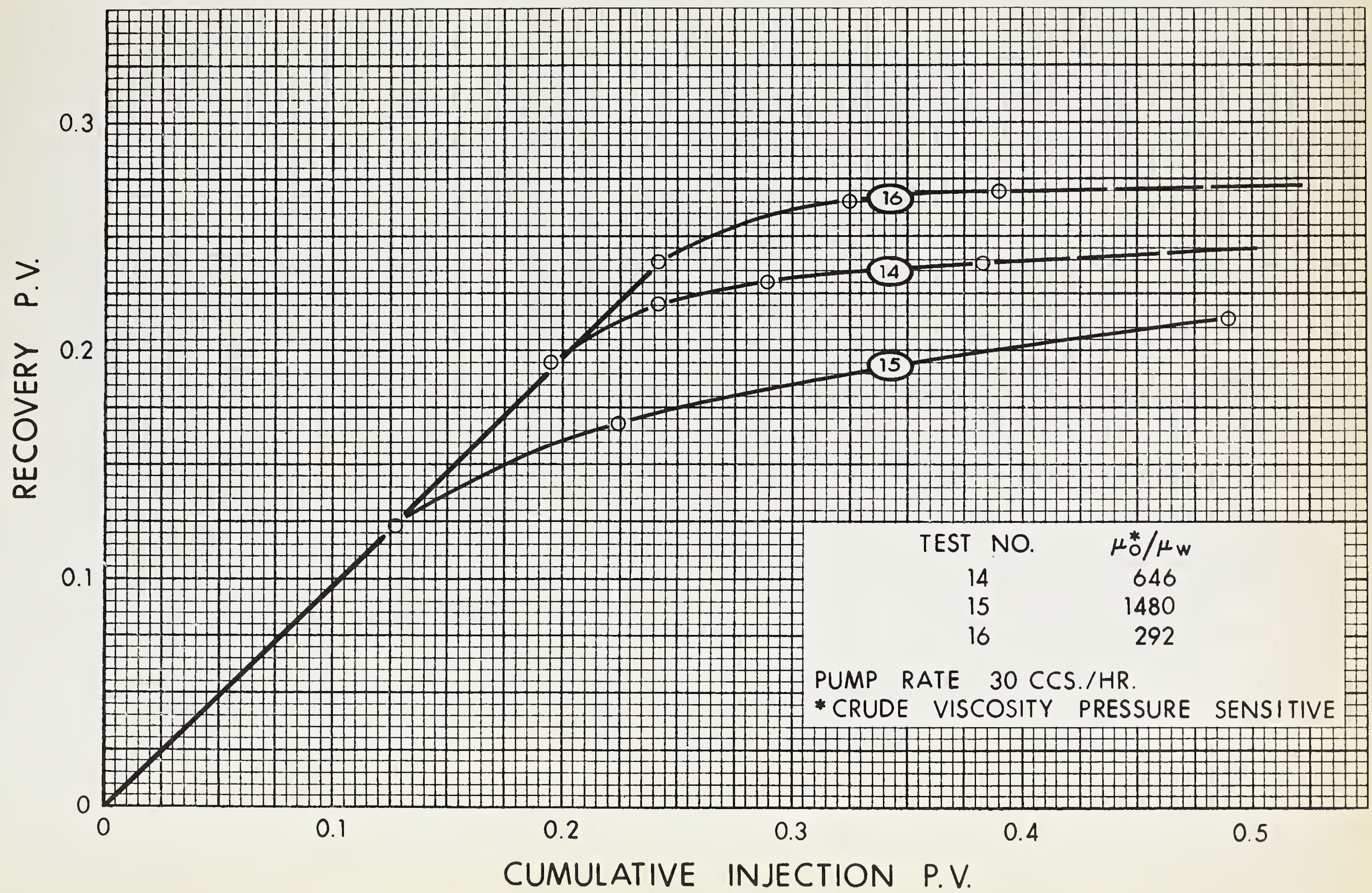

FIG. III - 2 RECOVERY HISTORY AT DIFFERENT VISCOSITY RATIOS

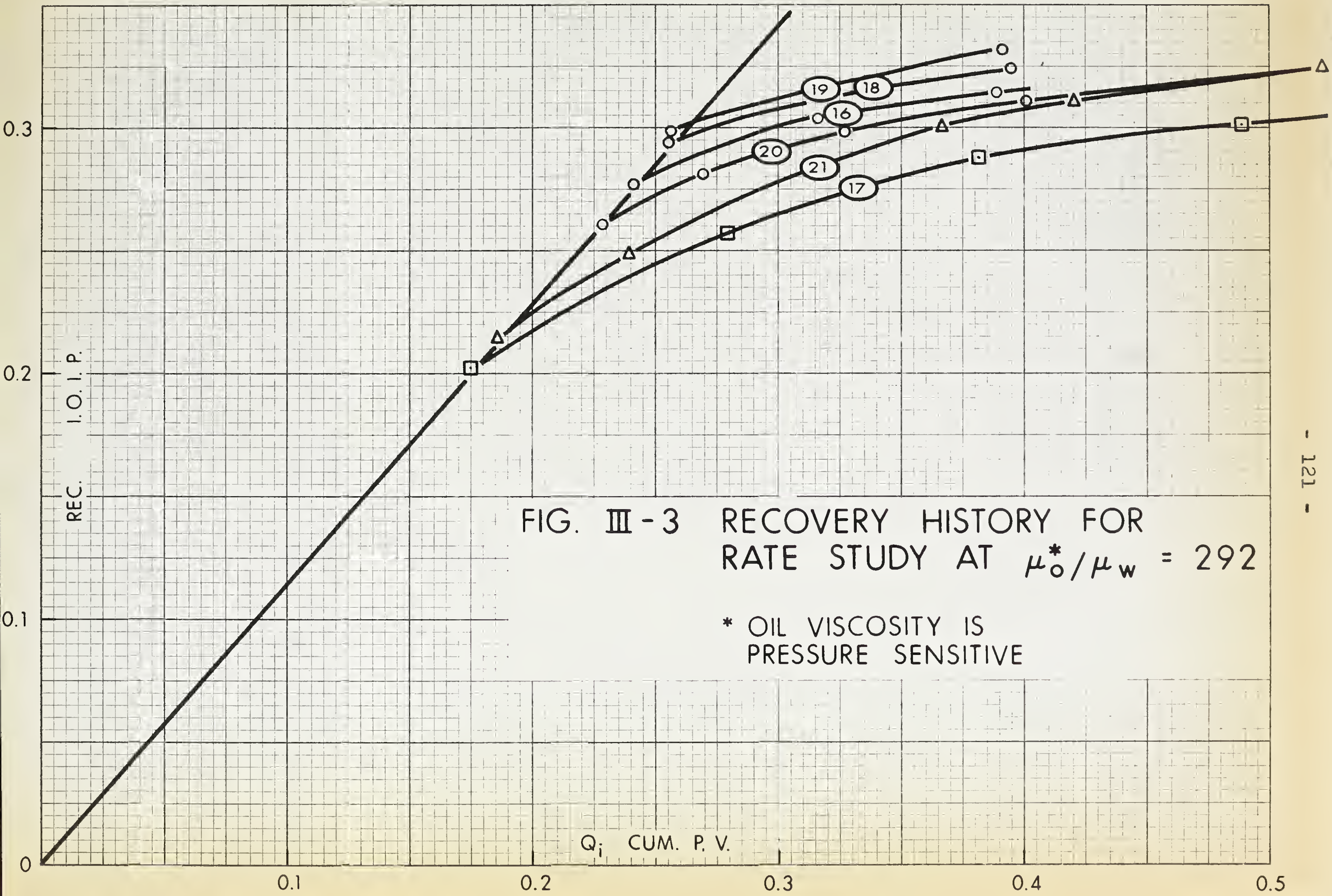

FIG. III-3 RECOVERY HISTORY FOR RATE STUDY AT $\mu_o^*/\mu_w = 292$

* OIL VISCOSITY IS PRESSURE SENSITIVE

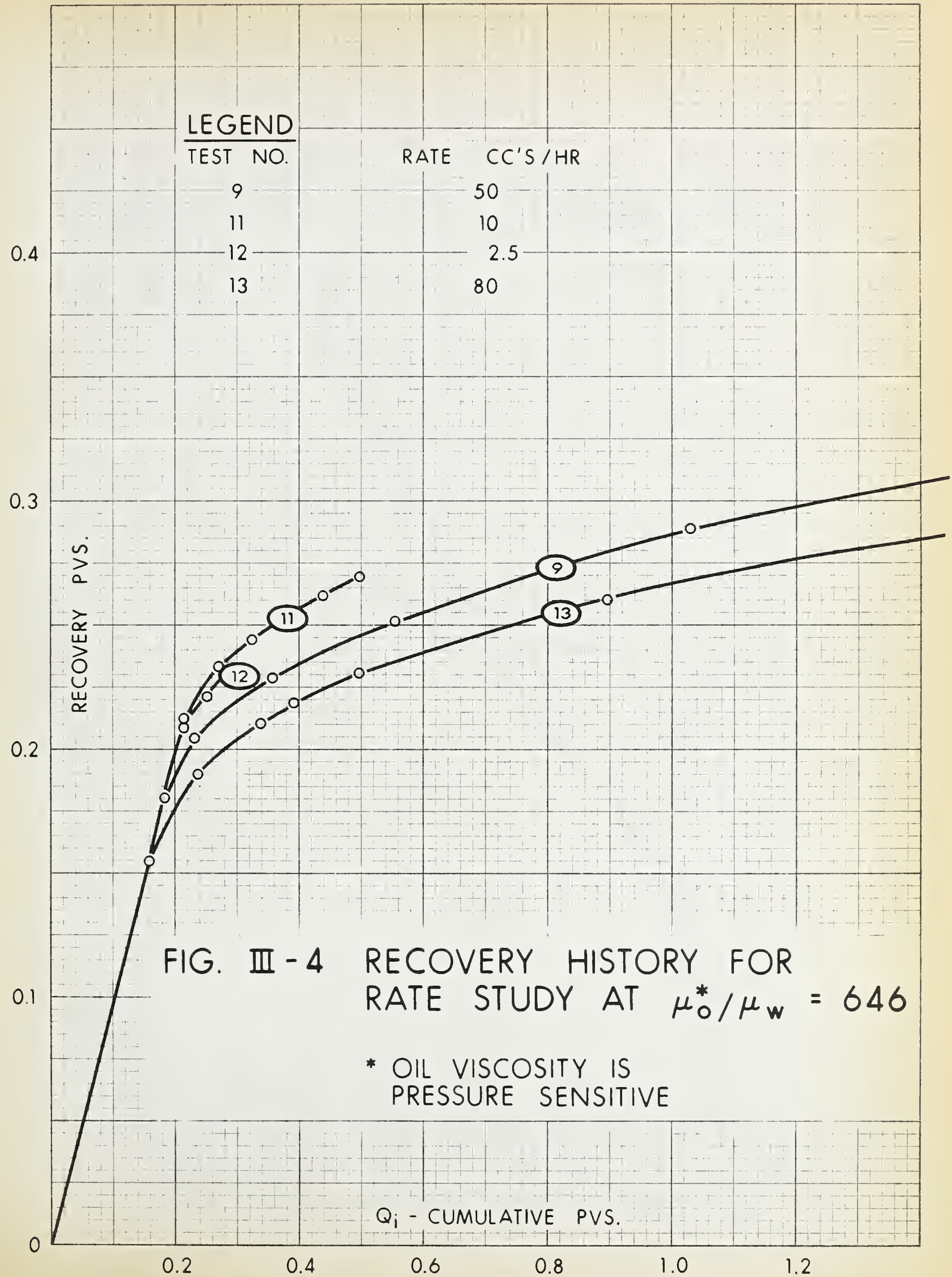

FIG. III - 4 RECOVERY HISTORY FOR RATE STUDY AT $\mu_o^*/\mu_w = 646$

* OIL VISCOSITY IS PRESSURE SENSITIVE

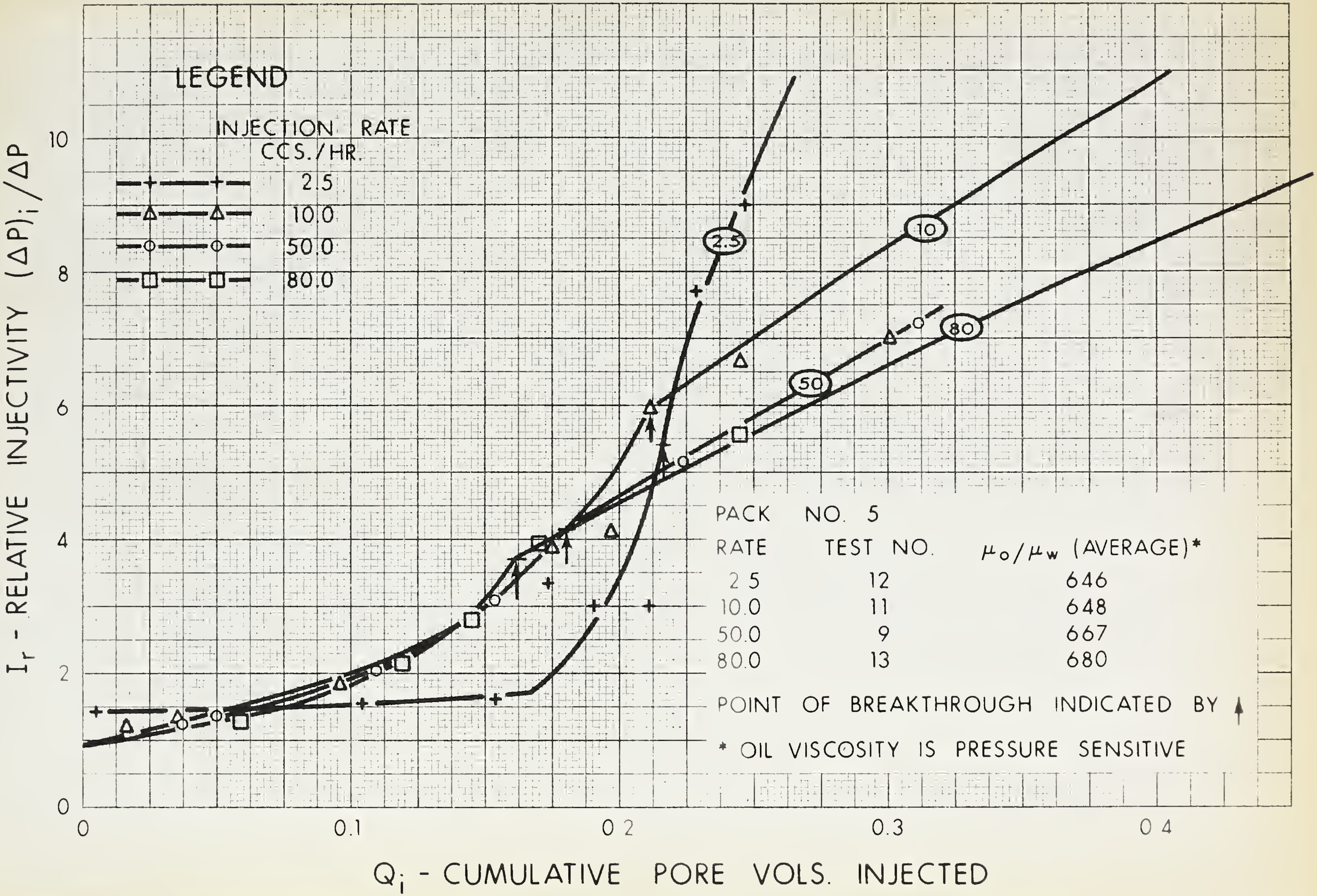

FIG. III-5 EFFECT OF INJECTION RATE ON RELATIVE INJECTIVITY